A burning issue

By Molly Parker
Staff Writer

"Sixteen, please." Giving an order laced with a Southern drawl, Bill McCall Jr. directed the elevator operator seated atop a five-gallon bucket to take him to the top of the boiler tower, a critical piece of the fourth power unit under construction at Santee Cooper's coal-fired facility in rural Cross.

Donning hard hats and safety goggles, McCall, who is Santee Cooper's chief operating officer, and two of his senior-level colleagues stepped out onto the open-planked structure.
From this vantage point, some 238 feet up in the air, heaps of coal below look like dark rolling hills.

Train cars bring in 10,000 tons a day of coal that is crushed as fine as baby powder and blown into a boiler that creates a hot steam—reaching temperatures as high as 1,055 degrees Fahrenheit—which spins a turbine that converts energy from a mechanical to an electrical state. It is then transmitted down three conductors to a transformer, jumped to 230,000 volts and shipped to the power grid.

It's the means by which electricity is provided to thousands of South Carolina businesses and homes, yet all the while, these towering structures spew noxious pollutants into the air—chief among them mercury, carbon dioxide, particulate matter and sulfur dioxide—though far less than they once did.

It is these chemical emissions—an inevitable byproduct of coal-generated power—that have become central in a debate about whether Santee Cooper should build another coal plant 70 miles northeast near Kingsburg on 2,700 acres of wetlands and pine forest neighboring the Great Pee Dee River.

photo/Andy Owens

Cooling towers emit steam at Santee Cooper's Cross Generating Station along the shores of Lake Moultrie. Santee Cooper has plans to build a similar station on the banks of the Great Pee Dee River in Florence County.

The state-owned utility expects to face a 525-megawatt shortfall in just five years without it, which Santee Cooper says will hamper the state's ability to attract business and industry. Santee Cooper promises that its facility, when built, will be the cleanest coal plant in the nation, perhaps in the world. That notion has been challenged by environmental groups hoping to thwart plans by convincing the state Department of Health and Environmental Control that it should not issue a permit for the plant.

"The fact that they say it doesn't make it so," said Blan Holman, an attorney for the Southern Environmental Law Center, which has threatened legal action as an alternative.

Environmental evolution

Some 60% of the footprint of each coal unit is made up of environmental controls. High-pressure fans suck the exhaust gas through a selective catalytic reduction process that strips it of nitrogen oxide, where it is run through a precipitator that removes particulate matter to the scrubbers.

Standing atop the Cross plant on a recent day, McCall pointed to the four massive scrubbers, one for each plant, outfitted with octopus-like metal tentacles that remove sulfur dioxide by shooting a mixture of limestone and water known as slurry at the exhaust gas waste, produced from of the combustion process.

When the first scrubber was built of steel and rubber nearly 25 years ago, it removed only 70% of sulfur dioxide, compared to the newest one made of concrete and tile that cleans away 96% of the pollutants shown to increase respiratory illnesses when present in the air.

The first Cross unit went online in 1983, the third at the beginning of this year. The fourth unit, upon which McCall stood, is still under construction.

Over the past two decades, the environmental controls have tightened and improved for coal-fired facilities, requiring less space in return for more efficiency.

The four units combined that will be running by 2009 are permitted to emit the same amount

of pollution as the two older units were allowed to cough out for a decade.

“This is what you call evolution,” he said.

All the units have now been updated to remove at least 93% of sulfur dioxide before the gas heads out the smoke stack and into the environment. The new coal units near the Pee Dee River would do even better, he said, removing 97% of sulfur dioxide, McCall said.

This evolution includes turning once-buried waste into usable products. For instance, oxygen is pumped into the scrubber to create calcium sulfate, also known as synthetic gypsum.
American Gypsum, a new $125 million, 100-employee plant in Georgetown, is expected to begin operating by year’s end. The plant will take calcium sulfate generated at Santee Cooper’s Cross and Winyah generating stations and turn it into wall board.

“I feel like we’ve been a research and development lab for this industry,” he said.

Economic consequences
Across the state, the economy would suffer, McCall said, if Santee Cooper could not deliver safe and reliable power, as it is mandated to do by state law.

But the environmental activists have painted their opposition with an economic brush as well.
The problem, said Holman, is that the new plant would eat into the region’s “increment,” or the clean-air budget for the area as measured by pollutants.

That budget is meant to prevent an area from moving into the so-called “nonattainment” status under the Clean Air Act that would threaten federal transportation dollars and future permitting applications for businesses.

“We’re dealing with a limited shared resource, which means we need to think carefully about how to dole it out,” he said. “Which would the region rather have, a tax-exempt coal plant staffed by 100 people, or several tax-paying Vought facilities employing thousands?”

Of particular concern is the plant’s proximity

to Cape Romain, a refuge owned by the U.S. Fish and Wildlife Service, which in 1997 identified that spot along with seven other national refugees as having the “highest air pollution threat.”

The air quality standards are stricter for the refuge, as with other congressionally designated areas, said Gudrun Thompson, also an attorney with the law center.

Environmental

Santee Cooper spokeswoman Laura Varn challenged the claim that the utility’s presence in Florence County will thwart other businesses. The plant will emit less pollutants than the permit would allow, she said, pointing to results from the new mercury monitoring system the utility installed a year ago to accurately test the tonnage it spits out.

Preliminary results found that the two units tested emit roughly 30 to 40 pounds per year, which would equate to about 160 pounds for all four units, well under the 187.2 pounds the plant is permitted to emit in total.

Critics argue even trace amounts of mercury can do significant damage because it can seep into the water and contaminate the fish population. DHEC already recommends eating no more than one serving per month of fish caught in certain areas where high levels of mercury have been detected.

Holman’s organization and the neighbors closest to the plant would like Santee Cooper to turn away from coal altogether.

“There’s no such thing as clean coal,” he said. “That’s like a healthy cigarette.”

They contend that Santee Cooper has yet to look at a comprehensive conservation package such as the one Charlotte-based Duke Energy has filed with the Public Service Commission of South Carolina.

Duke, which is also awaiting approval in North Carolina and Indiana, claims it can retire nearly 800 megawatts of energy that coal plants would otherwise produce by passing on the costs for efficiency upgrades to customers in the same way new plant construction can be passed on through rate increases.

McCall said it's easy to point fingers when you are not the one legally charged with keeping the lights on.

"I hope you know we don't want to build one," he said once back on the ground. "We build a plant only because we need it. I think some people believe we are out here trying to build a plant and we don't want to build a plant. This is a lot of work."

Molly Parker is a staff writer for the Business Journal. E-mail her directly at mparker@setcommedia.com.

Santee Cooper analyzes the needs of its customers in order to ensure it has a plan that will serve its customers in an economical and reliable manner. The process of developing a comprehensive plan to effectively serve the needs of the diverse customer classes involves several steps. In deciding what future resources are necessary to meet the customers' needs, it is necessary to first forecast the long-term load for each customer group. The weather sensitive portion of the forecast (excluding industrial customers) assumes normal weather temperatures and is developed based on key econometric factors known to influence energy consumption and peak demand. The forecast for Santee Cooper industrial customers is developed based on known contract changes of current customers. No consideration is given during the development of the load forecast for additional Santee Cooper industrial customers, meaning any new industrial customers' energy needs are not factored into the energy output required by Santee Cooper. The current load forecast shows a projected five-year average annual growth in winter demand of 2.5% as compared to a five-year historical average annual growth of 3.0%. For this reason the load forecast is conservative. The load forecast is then compared to Santee Cooper's existing capacity and planned reserve margins to determine how much generation is needed in the future to meet customer requirements. A generation plan is developed, and the adequacy of the transmission and distribution system is evaluated. Additionally, options to manage the customer's demand needs are evaluated.

The results of the 2005/2006 generation planning process, which included the evaluation of several generation options, determined that a new coal-fired unit (Pee Dee 1) was needed as early as 2012 to most economically and reliably meet the forecasted load growth of the Santee Cooper customer base. The models used during the generation planning process assume that Santee Cooper only builds capacity to meet projected customer needs, and does not build capacity for the purpose of off-system sales. Therefore, the resulting plan does not recommend building excess capacity over and above customer requirements.

33. Why was the timetable accelerated?

When the generation planning process was completed in early 2006, the optimal plan called for a coal-fired generating unit to be operational as soon as possible, but no later than 2014. The March, 2006 Board Resolution authorized management to take actions it deemed necessary or appropriate to construct a 600 MW coal unit to begin operation as soon as possible but not later than 2014. After further analysis and additional information, it was determined that the unit could be built as early as 2012 at an additional construction cost of less than 1.5%. Advancing the project schedule is expected, among other things, to save on fuel and purchased power costs, eliminate construction of a gas turbine in 2011, minimize the cost of any generating fleet outage, and allow the use of duplicate designs for some equipment thereby saving on spare parts inventory, all of which are expected to offset the additional construction cost. In May, 2006, the Santee Cooper Board approved an expedited date of 2012 and revised budget.

34. What accounts for the public announcements stating "Plans call for the 600-megawatt (MW) pulverized coal facility near Kingsburg, SC to begin commercial operation in January 2014" as recently as April 21, 2006 – yet the permit includes 2 ea. 660 MW facilities? Explain what the plans are for a second facility?

A second unit at the Pee Dee site was originally contemplated in 1983. The 2005/2006 generation planning process recommended one 600 MW coal unit to be built as soon as possible, but no later than 2014. Following the construction and operation of the Pee Dee unit, nuclear generation is recommended. However, Santee Cooper recognizes that there are inherent risks in the timely construction of a nuclear facility given the length of time since construction of a nuclear facility within the United States. Given the fact that the need for electricity will continue to grow, even despite conservation and efficiency measures, it is prudent for Santee Cooper to be prepared to build alternatives should the re-emergence of nuclear construction within the United States be delayed.

Everglades Restoration Plan sets forth the process for establishing the interim goals for the Comprehensive Everglades Restoration Plan. This section provides that the Interim Goals Agreements be developed by the Secretary of the Army, the Secretary of the Interior, and the Governor of the State of Florida in consultation with the Miccosukee Tribe of Indians of Florida, the Seminole Tribe of Florida, the Environmental Protection Agency, the Department of Commerce, other Federal, State, and local agencies, and the south Florida Ecosystem Restoration Task Force. In considering the interim goals to be indicated in the Interim Goals Agreement, the Secretary of the Army, Secretary of the Interior and the Governor of the State of Florida are required to consider the technical recommendations of RECOVER and any modifications to those recommendations by the Corps of Engineers, the Department of the Interior or the South Florida Water Management District. The programmatic regulations required that the Secretary of the Army afford the public an opportunity to comment on the proposed Interim Goals Agreement prior to its approval and notice in the **Federal Register** when the agreement has been finalized. The draft final of the Intergovernmental agreement was published in the **Federal Register** on November 3, 2006 (71 FR 64686). Public comments on the draft intergovernmental agreements establishing interim goals were accepted through December 4, 2006. The final intergovernmental agreement establishing the interim goals was signed on April 27, 2007. An electronic copy of the document is available at: *http://ww.evergladesplan.org/pm/progr_regs_igit_agreements.aspx.*

Brenda S. Bowen,

Army Federal Register Liaison Officer.

[FR Doc. 07–4377 Filed 9–6–07; 8:45 am]

BILLING CODE 3710–AJ–M

DEPARTMENT OF DEFENSE

Department of the Army; Corps of Engineers

Intent To Prepare an Environmental Impact Statement for the Pee Dee Electrical Generating Station in Florence County, SC

AGENCY: Department of the Army, U.S. Army Corps of Engineers.

ACTION: Notice of Intent.

SUMMARY: The U.S. Army Corps of Engineers, Charleston District intends to prepare an Environmental Impact Statement (EIS) to assess the potential social, economic and environmental effects of the proposed construction of a coal-fired electrical generating station with associated facilities, a rail line extension and transmission corridor by the South Carolina Public Service Authority (Santee Cooper), in the vicinity of the Bostic Landing on the Great Pee Dee River, in Florence County, South Carolina. The EIS will assess potential effects of a range of alternatives, including an alternative proposed in the Federal permit application.

DATES: *General Public Scoping Meetings:* Two Public Scoping meetings are being planned. The first will take place on Tuesday, September 25, 2007 from 6 p.m. to 9 p.m. at Coastal Carolina University located in Conway, South Carolina in the Recital Hall of the Edwards College of Humanities and Fine Arts. The second Public Scoping meeting will be held on Thursday, September 27, 2007 from 6 p.m. to 9 p.m. in the Commons Area and Auditorium of South Florence High School located at 3200 South Irby Street in Florence, South Carolina.

Federal and State Agency Scoping Meeting: A Federal and State Agency Scoping Meeting is planned to be held on Thursday, September 20, 2007 in Charleston, South Carolina.

FOR FURTHER INFORMATION CONTACT: For further information and/or questions about the proposed project and EIS, please contact Dr. Richard Darden, Project Manager, by telephone: 843–329–8043 or toll free 1–866–329–8187, or by mail: CESAC–RE–P, 69A Hagood Avenue, Charleston, SC 29403. For inquiries from the media, please contact the Corps, Charleston District Public Affairs Officer (PAO), Ms. Connie Gillette by telephone: (843) 329–8123.

SUPPLEMENTARY INFORMATION: An application for a Department of the Army permit was submitted by Santee Cooper pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. 403) and section 404 of the Clean Water Act (33 U.S.C. 1344) on December 11, 2006 and was advertised in a local public notice, P/N # SAC 2006–3574–SIB, on December 22, 2006. The public notice is available on Charleston District's public Web site at *http://www.sac.usace.army.mil/?action=publicnotices.pn2006*. Santee Cooper agreed that based on the potential social, economic, and environmental effects associated with the construction of the proposed Pee Dee Electrical Generating Station in Florence County, an EIS should be prepared by the Charleston District, Corps of Engineers.

1. *Description of Proposed Project.* The project proposed by the South Carolina Public Service Authority (Santee Cooper) is to construct a coal-fired electrical generating station with associated facilities on the Great Pee Dee River, in Florence County, SC. The proposed facility will involve the installation of an intake and discharge structure in the Great Pee Dee River in the vicinity of the Bostic Landing and this Notice of Intent will refer to the proposed project as the Pee Dee Station. The Pee Dee Station development will include the generating station structure and facilities that include intake and discharge structures, solid waste landfills, ash ponds, onsite-rail, rail switchyard, transmission lines, cooling towers, and roads. In total, approximately 93.75 acres of jurisdictional and non-jurisdictional wetlands may be impacted to construct the proposed Pee Dee Station. Construction of the Pee Dee Station may require filling an estimated 9.45 acres of jurisdictional wetlands and 5.10 acres of fill in non-jurisdictional wetlands, 8.14 acres of mechanized land clearing in jurisdictional wetlands, 2.32 acres mechanized land clearing in non-jurisdictional wetlands, and 0.67 acres of excavation in waters of the United States. Construction/upgrade of the rail line extension may require filling of 4.49 acres of jurisdictional wetlands and 4.90 acres of mechanized clearing. Construction of the transmission line may involve converting an estimated 58.68 acres of jurisdictional wetlands from forested wetlands to scrub shrub wetlands.

2. *Alternatives.* The following alternatives have been identified as reasonable alternatives that will be fully evaluated in the EIS: No Action; the modification of existing Santee Cooper facilities to meet the purpose and need of and for the proposed project; alternative locations within the jurisdictional authority of Santee Cooper where the proposed project might be developed; alternative facility layouts for the proposed Pee Dee Station; alternatives for energy generation, and mitigation measures. However, this list is not exclusive and additional alternatives may be considered for inclusion as reasonable alternatives.

3. *Scoping and Public Involvement Process.* Scoping meetings will be conducted to gather information on the scope of the project and the alternatives to be addressed in detail in the EIS. There will be three (3) sessions: One (1) Specifically for the Federal and State

agencies with regulatory responsibilities and two (2) for the general public that are being planned. Additional public and agency involvement will be gained through the implementation of a public outreach plan and agency coordination team.

4. *Significant Issues.* Issues associated with the proposed project to be given significant analysis in the EIS are likely to include, but may not be limited to, the potential impacts of the proposed Pee Dee Station on: Air quality, wetland quality, conservation, economics, aesthetics, general environmental concerns, wetlands, historic properties, fish and wildlife values, flood hazards, flood plain values, land use, navigation, shore erosion and accretion, recreation, water supply and conservation, energy needs, public health and safety, hazardous wastes and materials, food and fiber production, mineral needs, considerations of property ownership, environmental justice and, in general, the needs and welfare of the people.

5. *Cooperating Agencies.* S.C. Department of Health and Environmental Control, S.C. Department of Archives and History, U.S. Fish and Wildlife Service, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, and U.S. Environmental Protection Agency will be asked to participate as cooperating agencies.

6. *Additional Review and Consultation.* Additional review and consultation which will be incorporated into the preparation of this EIS will include, but shall not be limited to: Section 401 of Clean Water Act, the Magnuson-Stevens Fishery Conservation and Management Act, the National Environmental Policy Act, the National Historic Preservation Act; the Endangered Species Act, and the Clean Air Act.

7. *Availability of the Draft Environmental Impact Statement.* The Draft Environmental Impact Statement (DEIS) is anticipated to be available late in 2008. A Public Hearing will be conducted following the release of the DEIS.

Lieutenant Colonel J. Richard Jordan, III,

Commander, U.S. Army Corps of Engineers, Charleston District.

[FR Doc. E7–17685 Filed 9–6–07; 8:45 am]

BILLING CODE 3710–CH–P

DEPARTMENT OF DEFENSE

Department of the Army; Corps of Engineers

Notice of Intent To Hold a Public Meeting To Take Public Comments on the Draft Supplemental Environmental Impact Statement on Rock Mining in Wetlands in the Lake Belt Region of Miami-Dade County, FL

AGENCY: Department of the Army, U.S. Army Corps of Engineers, DoD.

ACTION: Notice of meeting.

SUMMARY: The U.S. Army Corps of Engineers (Corps) Jacksonville District issued a draft Supplemental Environmental Impact Statement (SEIS) on August 17, 2007 to evaluate potential impacts of further rock mining within wetlands in western Miami-Dade County, FL. In order to accept public comments on the Draft SEIS, the Corps has scheduled a public meeting. The Corps invites Federal agencies, American Indian Tribal Nations, state and local governments, and other interested private organizations and parties to attend the public meeting and to comment on the draft SEIS.

DATES: The Corps plans to hold a public meeting on September 18, 2007 at 6:30 p.m. EST.

ADDRESSES: The meeting will be held at the Miami Dade Fire Rescue Headquarters, 9300 NW 41st Street, Doral, FL 33178. (786) 331–5000.

FOR FURTHER INFORMATION CONTACT: Ms. Leah Oberlin, (561) 472–3506.

SUPPLEMENTARY INFORMATION: The Corps will provide additional notification of the meeting time and location through newspaper advertisements and other means. Following a short presentation on the draft SEIS, verbal and written comments on the draft SEIS will be accepted. A transcript of verbal comments will be generated to ensure accuracy. A spanish language translator will be available. To submit comments on the draft SEIS or to request copies of materials related to this effort as they become available to the public, contact: Ms. Leah Oberlin, U.S. Army Corps of Engineers, Regulatory Division, Palm Beach Gardens Regulatory Office, 4400 PGA Boulevard, Suite 500, Palm Beach Gardens, FL, 33410, by e-mail at *Leah.A.Oberlin@saj02.usace.army.mil*, or by telephone at (561) 472–3506. Comments or requests for information can also be submitted on the Lake Belt SEIS Web site at *http://www.lakebeltseis.com*. The Corps will consider all comments for the scope of the SEIS received by October 16, 2007.

Brenda S. Bowen,

Army Federal Register Liaison Officer.

[FR Doc. 07–4378 Filed 9–6–07; 8:45 am]

BILLING CODE 3710–AJ–M

DEPARTMENT OF EDUCATION

Submission for OMB Review; Comment Request

AGENCY: Department of Education.

SUMMARY: The IC Clearance Official, Regulatory Information Management Services, Office of Management invites comments on the submission for OMB review as required by the Paperwork Reduction Act of 1995.

DATES: Interested persons are invited to submit comments on or before October 9, 2007.

ADDRESSES: Written comments should be addressed to the Office of Information and Regulatory Affairs, Attention: Education Desk Officer, Office of Management and Budget, 725 17th Street, NW., Room 10222, Washington, DC 20503. Commenters are encouraged to submit responses electronically by e-mail to *oira_submission@omb.eop.gov* or via fax to (202) 395–6974. Commenters should include the following subject line in their response ''Comment: [insert OMB number], [insert abbreviated collection name, e.g., ''Upward Bound Evaluation'']. Persons submitting comments electronically should not submit paper copies.

SUPPLEMENTARY INFORMATION: Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that the Office of Management and Budget (OMB) provide interested Federal agencies and the public an early opportunity to comment on information collection requests. OMB may amend or waive the requirement for public consultation to the extent that public participation in the approval process would defeat the purpose of the information collection, violate State or Federal law, or substantially interfere with any agency's ability to perform its statutory obligations. The IC Clearance Official, Regulatory Information Management Services, Office of Management, publishes that notice containing proposed information collection requests prior to submission of these requests to OMB. Each proposed information collection, grouped by office, contains the following: (1) Type of review requested, e.g., new, revision, extension, existing or reinstatement; (2) Title; (3) Summary

FACT SHEET
ENVIRONMENTAL PERMITTING OF COAL-FIRED POWER PLANTS IN MICHIGAN
June 29, 2007

Michigan's 21st Century Energy Plan (Plan) dated January 2007 identifies the need for new coal-fired generating capacity. The Plan acknowledged that coal will remain a large part of Michigan's portfolio for the foreseeable future. As a result, the Michigan Department of Environmental Quality (MDEQ) anticipates several permit applications in the near future. After consideration of the applicable federal and state requirements, the impact on emissions, and the recent permitting activities throughout the country, the MDEQ is proposing to require the consideration of clean coal technologies (i.e. Integrated Gasification Combined Cycle or "IGCC") as part of the air permitting process for electric generating units.

There have been a number of significant activities relative to this issue since Michigan's last coal-fired power plant was permitted in 1984. These activities include:

- The federal Clean Air Act was amended in 1990. One of the changes made was to the definition of Best Available Control Technology (BACT), which was intended to add clean coal technology (Title 40 of the Code of Federal Regulations, Part 52.21(12)). Michigan rules were modified in 2006 and include the same definition.

  > Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source of modification ***through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques*** for control of such pollutant…. [Emphasis added.]

- IGCC technology has progressed from an experimental technology. There are two existing installations of IGCC technology for power generation in the United States. One is located in Tampa, Florida and the other is in Terre Haute, Indiana. Both of these installations were partially funded by U.S. Department of Energy money. More IGCC facilities are planned. There are at least three IGCC facilities in the Great Lakes Region which have been permitted, or are in the final states of permitting. The MDEQ is aware of approximately 13 new IGCC units in the planning stages throughout the country. The availability and reliability of IGCC facilities has been steadily increasing, and new IGCC facilities have reliabilities comparable to conventional coal-fired power plants.

- The state of Michigan formally recognized the need to control mercury from coal-fired power plants. On June 20, 2005, Michigan's Mercury Electric Utility Workgroup released its report entitled: *Mercury Electric Utility Workgroup Final Report*. The workgroup was formed in response to a request by Governor Jennifer M. Granholm to MDEQ Director Steven E. Chester. The workgroup was charged with evaluating opportunities and developing recommendations for an emission reduction strategy for coal-fired electric generating units and determining the feasibility of timely and measurable reductions in mercury emissions. Mercury control on IGCC plants is significantly more effective than mercury control on conventional coal-fired power plants.

IGCC has superior sulfur dioxide, nitrogen oxides, particulate matter, and mercury control, resulting in significantly lower emissions of these pollutants compared to conventional coal-fired facilities.

With the advent of climate change as a national issue, the ability to capture and sequester carbon emissions has become a concern related to coal-fired power plants. As an outfall to these considerations, it has been noted that Michigan has unique geological formations which could make carbon sequestration in Michigan both economically and technically advantageous. IGCC has a much higher potential for carbon capture than conventional facilities. As climate change strategies are implemented, these considerations will serve to offset IGCC's higher capital and operating costs in Michigan more than in other locations.

The states of Illinois, Kentucky, and New Mexico require IGCC to be considered as a control option in their BACT determinations. Two IGCC power plants, the Taylorville Energy Center in Illinois and the Cash Creek Generation Station in Kentucky, have recently been permitted or are in the final stages of permitting.

In cases where states have not included IGCC technology as a part of their BACT review, legal challenges have been filed. These cases are still pending resolution approximately four to five years after permit issuance. It is likely that permits in Michigan would be challenged if IGCC is not included as a part of a BACT determination.

Based on these considerations, the MDEQ is proposing to require the consideration of IGCC as a control option within a BACT review, since the technology:

- Falls within the scope of the regulatory language;
- Is consistent with policy and guidance provided by the U.S. Environmental Protection Agency;
- Achieves better environmental performance than conventional technologies;
- Offers significant advantages, some unique to Michigan, over other technologies for the reduction or control of secondary pollutants and their impacts (i.e., mercury, greenhouse gases); and,
- Reduces the risk of administrative or legal challenges to any permit issued without its consideration.

SOUTHERN ENVIRONMENTAL LAW CENTER

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Charlottesville, VA
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October 10, 2007

Jody Hamm, Director
Freedom of Information Center
SC DHEC
2600 Bull Street
Columbia, SC 29201

Via Electronic Mail and U.S. Mail

Re: SC FOIA Request—Pee Dee Plant

Dear Mr. Hamm:

Pursuant to the South Carolina Freedom of Information Act ("SC FOIA"), S.C. Code § 30-4-10 et seq., the Southern Environmental Law Center ("SELC") requests the opportunity to review and copy certain records. Specifically, we request access to documents relating to air quality permitting for Santee Cooper's proposed Pee Dee Generating Station (the "Pee Dee plant") near Kingsburg, South Carolina that have been generated by or come into the possession of the S.C. Department of Health and Environmental Control ("DHEC") since our request dated May 1, 2007.

The SC FOIA requires that all responsive documents prepared, owned, used, in the possession of, or retained by DHEC be made available for review, regardless of physical form or characteristics. S.C. Code § 30-4-20(c).

The requested documents include, but are not limited to, internal and interagency meeting notes; electronic mail messages, facsimile transmissions, telephone logs, correspondence, notes or other records of communications with other federal state agencies, elected officials, or members of the public; and comments submitted by the public and by state and federal agencies. I emphasize that this request includes electronic mail correspondence and attachments thereto, which may be produced in either printed or electronic format. This request also specifically includes documents prepared by contractors that Santee Cooper may have hired to assist in preparing or processing its permit application for the above-referenced facility. This request also includes computer modeling archives. Specifically, I am requesting the following modeling files for the Class I impact analyses:

1) All emission rate calculations and tables submitted by the Applicant for the proposed Pee Dee plant. Please provide these calculations and tables in the form of native excel spreadsheets (.xls file extension).

2) All meteorological data for the Class I modeling for the proposed Pee Dee plant, including all CALMET input and output files used to prepare the CALPUFF Class I impact analyses.

3) All other files necessary to prepare the CALMET modeling, including any TERREL, CTGCOMP, CTGPROC, and MAKEGEO inputs and outputs used to create the inputs to CALMET.

4) All air quality and other non-meteorological data used in the CALPUFF Class I impact analyses.

In addition, I am requesting the following for the Class II impact analyses:

1) All AERMOD input files, including surface and upper air meteorological data.

2) All emission rate calculations and tables submitted by the Applicant for the proposed Santee Cooper Pee Dee generation facility. Please provide these calculations and tables in the form of native excel spreadsheets (.xls file extension).

3) Any and all terrain and land use/land cover files used in these analyses.

4) Any and all FORTRAN programs (including code) and other spreadsheets used in preparing and reviewing the permit application.

In essence, please provide all the electronic files necessary to recreate the Pee Dee generation plant emission calculations and tables, as well as the complete Class I impact analyses.

SELC is a non-profit environmental organization that seeks the requested records on behalf of its members to protect its interests and those of the general public. Therefore, consistent with the SC FOIA's stated policy of "mak[ing] it possible for citizens, or their representatives, to learn and report fully the activities of their public officials at a minimum cost or delay to the persons seeking access to public documents or meetings," S.C. Code Ann. § 30-4-15, we request that DHEC provide us with access to and copies of these documents without charge or at a reduced charge. With respect to our request, "waiver or reduction of the fee is in the public interest because furnishing the information can be considered as primarily benefiting the general public." S.C. Code § 30-4-30(b). If DHEC denies our request for a fee waiver, please contact me before incurring costs if amassing the documents will amount to more than $200 in fees.

Although I am aware that the statute does not require a final response to this request until 15 days of its receipt, S.C Code § 30-4-30(c), given the time-sensitive nature of this request and the impending public comment deadline, I request that you provide access to these documents as quickly as possible. Should the volume of responsive documents be large, I ask that the documents be made available for inspection by this office prior to any copying. Please note that I understand some of the electronic files may be very large and are willing to make whatever arrangements necessary to facilitate their transmission to us. Please contact me at your earliest convenience to arrange for our review of these documents.

Thank you for your prompt attention to this matter. If you have any questions regarding this request, please contact me at (919) 967-1450 or gthompson@selcnc.org.

Sincerely,

Gudrun Thompson

Kate Double

From: Joseph Eller [ELLERJC@dhec.sc.gov]
Sent: Thursday, January 03, 2008 2:40 PM
To: camille.marie@sbcglobal.net
Subject: Follow-up Note

Just to let you know, Camille, that I did not find any electronic documents on the Santee Cooper Pee Dee emissions other than PDF format (besides the modeling files).

Joe Eller, BAQ Permitting
Phone: (803) 898-3831
Fax: (803) 898-4079
Email: ellerjc@dhec.sc.gov

South Carolina Department of Health and Environmental Control

Final Early Action Compact SIP
December 29, 2004

South Carolina's Draft Early Action Compact SIP

1.1. Executive Summary

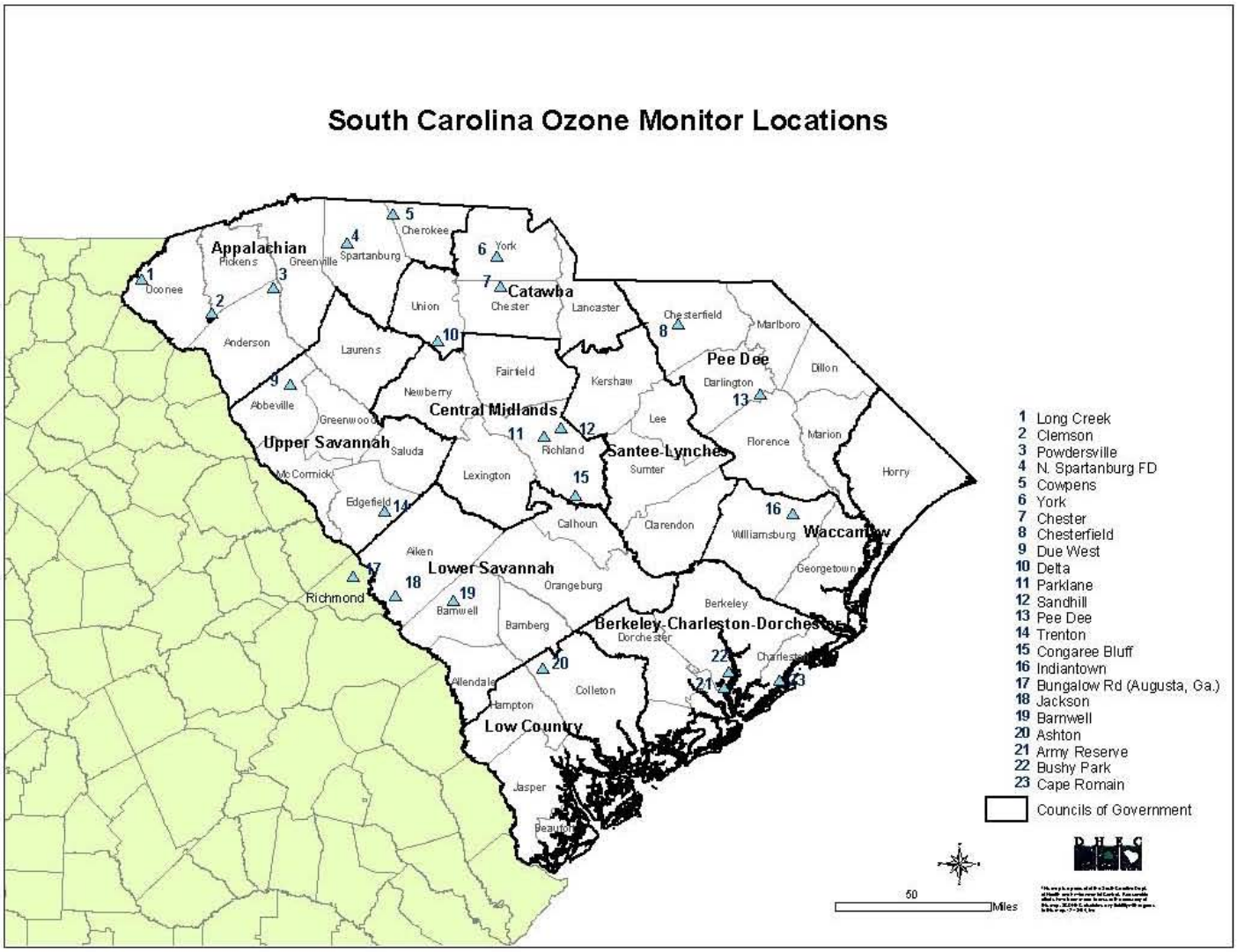
On July 19, 2002, the United States Environmental Protection Agency (EPA) endorsed a protocol for developing voluntary 8-hour ozone Early Action Compacts (EACs) (Appendix 1). EPA's stated purpose for the EAC process is to provide local areas with flexibility to control air emission from their sources and offer a means to achieve cleaner air sooner than the Clean Air Act requires. Only areas that are attaining the 1-hour ozone standard are eligible to participate in the EAC process. The compact requires these areas to attain the 8-hour ozone standard by December 31, 2007, a date that is sooner than would otherwise be required through the traditional nonattainment designation process. The compacts include all necessary elements of a comprehensive air quality plan, but are tailored to local needs and driven by local decisions. As a result of an area's participation, the EAC process calls for EPA to recognize the area's commitment to early action by provisionally deferring the effective date of the nonattainment designation. The deferral of the effective date of the designation is contingent upon the participating area's meeting all terms and key milestones of the compact. Further, the process provides for "fail-safe" provisions for the area to revert to the traditional process if specific milestones are not met.

In December 2002, the South Carolina Department of Health and Environmental Control (Department) entered into compacts with EPA and local governments for the purpose of bringing cleaner air sooner to the citizens of South Carolina (Appendix 2). Forty-five of forty-six counties signed compacts and they were grouped into the ten areas listed below:

1. Appalachian: Anderson, Cherokee, Greenville, Oconee, Pickens, Spartanburg
2. Catawba: Chester, Lancaster, Union, York
3. Pee Dee: Chesterfield, Darlington, Dillon, Florence, Marion, Marlboro
4. Waccamaw: Georgetown, Horry, Williamsburg
5. Santee Lynches: Clarendon, Kershaw, Lee, Sumter
6. Berkeley-Charleston-Dorchester: Berkeley, Charleston, Dorchester
7. Low Country: Beaufort, Colleton, Hampton, Jasper
8. Lower Savannah: Aiken, Allendale, Bamberg, Barnwell, Calhoun, Orangeburg
9. Central Midlands: Fairfield, Lexington, Newberry, Richland
10. Upper Savannah: Abbeville, Edgefield, Greenwood, Laurens, Saluda

Since that time, the Department has been meeting with local governments, industry representatives, environmental groups, and other interested parties, to develop state-wide regulations and assist in the development of local ozone reduction strategies to fulfill the commitments under the compacts. In accordance with the EAC process, on March 31, 2004, the Department submitted the final local early action plans to EPA. Based on this submittal and the EAC areas' continuing efforts, EPA published the first deferral of the effective date of the nonattainment designations on April 30, 2004. This final rule defers the effective date of nonattainment designations until September 30, 2005. In accordance with the compact requirements, the Department is providing the attached document to

fulfill its commitment to submit a final EAC SIP by December 31, 2004, consisting of local plans, all adopted control measures, and a demonstration that the areas will attain the 8-hour ozone standard by December 31, 2007.



1.2. Early Action Compact Requirements

The compacts that were signed by the Department, EPA, and local governments in December 2002, specify the requirements that must be met by participating EAC areas. These requirements are as follows:

- Milestones and Reporting (Attachment A)
- Emissions Inventories (Attachment B)
- Modeling (Attachment C)
- Control Strategies (Attachment D)
- Maintenance for Growth (Attachment E)

- Public Involvement (Attachment F)

The attached SIP submittal provides detailed discussions and documentation to support how the State and local areas have met their commitments with respect to the compact requirements.

1.3. Modeling Results

One of the key requirements of the EAC process is that areas attain the 8-hour ozone standard by December 31, 2007, and beyond. For a monitoring site to pass the attainment test, the three-year average of the annual fourth highest 8-hour ozone concentration must not exceed 84 parts per billion (ppb). The three-year average is based on monitoring results for the years 2005, 2006, and 2007. As discussed in Attachment C and then in more detail in Appendix 5, modeling indicates that the 2007 estimated design values for all sites are less than or equal to 84 ppb. Furthermore, the compacts require areas to address growth for five years beyond December 31, 2007, to ensure that the area remains in attainment. To demonstrate this, areas may use modeling analysis showing 8-hour ozone levels below the standard in 2012. The Department conducted modeling analysis for, not only 2012, but also for 2017 and the results as provided in Attachment E are that for 2012 and 2017 the estimated design values for all sites are less than or equal to 84 ppb.

1.4. Control Strategies

The modeling analysis described above demonstrates that all monitors in South Carolina will be attaining the 8-hour standard without the inclusion of measures beyond the national and regional programs already finalized. The *Protocol for Early Action Compacts* endorsed by EPA states that "after all Federal and State controls that have been or will be implemented by December 31, 2007, are accounted for in the modeling, the local area will identify additional local controls, as necessary, to demonstrate attainment of the 8-hour ozone standard on or before December 31, 2007." While additional control measures from local areas were not needed to attain the 8-hour ozone standard by December 31, 2007, the State and local areas continued to move forward to develop strategies to reduce emissions in South Carolina to demonstrate their commitment to the process.

The EAC process encourages state and local areas to design control strategies that best fit their specific needs. As part of this process the Department began meeting in 2002 with local governments, industry representatives, environmental groups, and other state and federal agencies in an effort to develop state and local control strategies to reduce ozone precursors as part of the commitments under the compacts. The Department tackled these requirements from many different perspectives. First, the Department met regularly with the local EAC areas to consult with them and provide them with assistance on developing the local plans. Second, the Department formed stakeholder groups and conducted monthly meetings in an effort to develop state-wide regulations to achieve additional reductions in ozone precursors to support the EAC process. In addition, the Department

worked with several major NO_x emission sources in critical areas to seek agreements for additional source specific NO_x reductions. Also, in an effort to garner further support for the process from the state legislature and other state agencies, the Department worked successfully to get a concurrent resolution passed endorsing the process. Finally, the Department has conducted interagency meetings between air quality and transportation officials to develop a Smart Highways checklist to be used in transportation planning.

Most of the local measures described above are voluntary and will not be quantified, but will nonetheless have tangible benefits to air quality. For instance, with respect to the local measures described in Attachment D, some of the strategies adopted as part of this process include anti-idling measures for county vehicles, hosting gas can exchange programs, and assigning an air quality contact for the county who is responsible for disseminating air quality information. While these measures are difficult to quantify, they will still have a positive impact on air quality and raising awareness about air quality issues. Also, most of these local areas have attained the 8-hour ozone standard but are still engaged in this process to ensure that their areas continue to support air quality improvement efforts. Thus, the Department is including all local plans to demonstrate their commitment to the process. The local measures described in Appendix 16 demonstrate not only the commitment of the local areas but also the ownership that these areas are taking of this effort. They recognize the day-to-day activities that contribute to air quality. One such example of this is assigning an Air Quality Contact person in the County, responsible for disseminating the Ozone forecasts and related information on Ozone Action Days. Additionally, many counties have implemented carpooling programs and flex scheduling to coordinate with Ozone Action Days. Greenville County has committed to improving landscaping at all County facilities with the goal of improving the environment by minimizing turf areas and replacing them with shrubs, bed areas, and trees; enhance appearance; and reducing maintenance and associated costs. Greenville County, Georgetown County and Lexington County are implementing energy conservation measures to include sending reminders for employees to turn off lights and computers at the end of the day. Chester County has committed to plant 500 hardwood trees to help secure air quality and will also revise their purchasing policy to buy in bulk and reduce packaging. Georgetown County will develop a bike trail system in the county and will purchase electric cars for on site mobilizations. Sumter County will schedule maintenance activities to avod peak time emissions during ozone alerts and has proposed changes to the current tree ordinance to protect existing trees in new developments. Many counties will consider the purchase of alternative fueled or more fuel-efficient vehicles when buying replacements. These are just a few of the behavioral changes being implemented in the counties that will provide air quality benefits now and in the future.

Among the key control strategies that were developed as part of the EAC process, were revisions to state-wide regulations for the purpose of providing additional reductions in ozone precursors. R.61-62.5 Standard 5.2, *Control of Oxides of Nitrogen*, and R.61-62.2, *Prohibition of Open Burning,* were published in the *South Carolina State Register* on June 25, 2004, and became effective upon publication (Appendix 9). R.61-62.5, Standard 5.2, *Control of Oxides of Nitrogen*, is a newly-developed regulation that applies to new and existing stationary sources that emit or have the potential to emit NO_x generated from

fuel combustion. This regulation sets standards for new construction based on Best Available Control Technology (BACT) standards from the national RACT/BACT/LAER Clearinghouse. For new sources, the regulation is primarily directed at smaller sources that fall below the Prevention of Significant Deterioration (PSD) thresholds and therefore would otherwise be exempt for NO_x controls altogether. R.61-62.2, *Prohibition of Open Burning,* is an existing state regulation that has been revised as part of this process to seek additional NO_x and VOC reductions. Specifically, the regulation was revised to clearly ban the burning of household trash statewide and therefore, in all local EAC areas. Prior to this revision, household trash was allowed to be burned when other disposal options were unavailable. Deleting this exemption removes any ambiguity in the regulation with respect to the burning household trash and will be helpful to the Department with respect to the enforcement of this provision and will also help us to achieve addition reductions in ozone precursors. In addition, the exemption for the burning of construction waste was revised to allow only residential construction waste to be burned if certain provisions are met such as the requirement that only clean lumber be burned and only outside of the ozone season. Other construction waste that is not associated with the building and construction of one and two family dwellings is strictly prohibited.

While information pertaining to the amount of NO_x and VOC reductions that are expected as a result of these regulations is provided in Attachment D, it is important to note that modeling indicates that all monitors will be attaining the 8-hour standard by 2007 even without these additional measures. However, the reductions from these regulations are quantifiable, permanent and will ensure that South Carolina obtains cleaner air sooner and helps ensure continued maintenance of the 8-hour ozone standard in the future. For example, R.61-62.5, Standard 5.2, became effective in June of 2004. Since that date, the Department has permitted two 12.56mmBtu/hr boilers at the Oconee Memorial Hospital that were required to install low NO_x burners as a result of this regulation. These are the types of smaller sources that would otherwise not be required to install NO_x controls. Furthermore, we have received and are in the process of permitting several additional applications from facilities that will be impacted by this regulation.

Another significant control strategy that was developed through this process is the voluntary commitments that the Department has negotiated with several of the state's largest existing industrial sources to reduce and/or limit their NO_x emissions. These negotiations were the direct result of the EAC process as are the NO_x reductions that will result from them. These voluntary commitments are described in more detail in Attachment D, but in summary, SCE& G – Wateree in Richland County has agreed to take permit limits on two coal-fired boilers and International Paper in Richland County has agreed to take an annual allowable NO_x emission reduction of 1000 tons, facility-wide. In addition, Duke Power in Anderson County has voluntarily agreed to install advanced low NO_x burners on two coal-fired boilers. This is a $7 million investment by Duke Power that will result in approximately 850 tons of NO_x reduced annually. Finally, as part of this process, Transcontinental Gas Pipeline Corporation (Transco) which operates the internal combustion engines at Station 140 in Spartanburg County, has agreed to begin early implementation of the NOx emission reductions required by Phase

II of EPA's NOx SIP Call regulation. In accordance with the federal requirements, Phase II is required to be fully implemented by 2007. As part of the EAC process, Transco has begin engine overhauls and engine combustion modifications so that these NOx emission reductions can be fully implemented by December 2005, well ahead of the federal timeline.

The Department believes that the sum of all these efforts will have a very real and positive impact on the health and environment of South Carolina. The EAC process has allowed the state of South Carolina to achieve reductions in ozone precursors from a variety of sources that otherwise would not have occurred and this was all done on a timeframe that was sooner than what would be required through the traditional nonattainment designation process. In addition, as a result of the local EAC plans and local efforts, awareness of air quality issues has been raised to a level that would not have been possible without the EAC process. People from around the state, who have never previously had any significant exposure to air quality issues, have participated in the EAC process and helped make decisions about improving air quality. This is perhaps, above all else, the reason why the South Carolina Wildlife Federation chose to honor the "SCDHEC Early Action Compact SIP" with their 2005 South Carolina Wildlife Federation Air Conservation Award, an award that has only been bestowed six times since 1970 (see Appendix 15).

1.5 List of Appendices

Appendix 1 – EPA Protocol for Early Action Compacts (June 19, 2002)
Appendix 2 – South Carolina Early Action Compacts
Appendix 3 - 8-hour Ozone Modeling Analysis and Attainment Demonstration: Technical Protocol
Appendix 4 – 8-hour Ozone Modeling Analysis and Attainment Demonstration: Technical Support Document Executive Summary
Appendix 5 – 8-hour Ozone Modeling Analysis and Attainment Demonstration: Technical Support Document
Appendix 6 – 8-hour Ozone Modeling Analysis and Attainment Demonstration: Georgia EPD Modeling Data
Appendix 7 – Letters sent to EPA to meet the milestones and reporting requirements of the Early Action Compacts
Appendix 8 – Local Early Action Plans
Appendix 9 – Early Action Compact Regulations
Appendix 10 – Memorandums of Agreement and Letters of Commitment
Appendix 11 - Concurrent Resolution - H.3914
Appendix 12 - Smart Highways Checklist
Appendix 13 – Estimated Emission Reductions Achieved by Regulation 61-62.2, Prohibition of Open Burning, and Regulation 61-62.5, Standard 5.2, *Control of Oxides of Nitrogen*
Appendix 14 – Letters to EPA Concerning Selection of 1998 Emissions Inventory
Appendix 15 – Letter from the South Carolina Wildlife Federation concerning the 2005 South Carolina Wildlife Federation Air Conservation Award

Attachment A

Milestones and Reporting

A. Milestones and Reporting

The compacts that were signed by the Department, EPA and local governments include clearly measurable milestones that are critical to assess the compact's development. Meeting these milestones is an important tool to measure the success of the EAC process and ensure that the areas are making progress towards developing and implementing the early action SIP. For continued participation in this process, the EACs include "key" milestones that must be met. To date, the participating areas have met all of the milestones required by their EACs. As a result, EPA proposed in the Federal Register, December 16, 2003, that when it promulgated the designations for certain areas of the country not meeting the 8-hour ozone standard, EPA will issue the first of three deferrals of the effective date of the designation for any EAC area that is designated nonattainment and continues to meet all compact milestones. As stated in the Federal Register, the EPA believes this program provides an incentive for early planning, early implementation and early reductions of emissions leading to expeditious attainment and maintenance of the 8-hour ozone standard. The EPA also noted that the EACs give local areas the flexibility to develop their own approach to meeting the 8-hour ozone standard. On April 30, 2004, with an effective date of June 15, 2005, EPA issued the air quality designations and classifications for areas for the 8-hour ozone standard. In this rulemaking, EPA also promulgated the first deferral of the effective date, to September 30, 2005, for the nonattainment designation for EAC areas that have met all milestones through March 31, 2004.

The following table outlines all the milestones agreed to in the compacts including those eight "key" milestones in **bold**, required for continued participation in the EAC process. Information regarding the status of each milestone completed to date is included. In addition, copies of the compacts are provided as Appendix 2 and copies of letters to EPA are provided as Appendix 7 to provide further evidence of the commitment of the South Carolina EAC areas toward meeting the goals of the compacts.

DATE	MILESTONE	STATUS
12/31/02	**EAC signed by all parties and submitted to EPA**	**45 counties entered into EAC's with the Department and EPA. Three separate submittals to EPA were made on: December 20, 2002; December 27, 2002; and, December 31, 2002.**
12/31/02	Initial modeling emissions inventory completed	This was addressed in correspondence to Mr. J.I. Palmer, Regional Administrator, EPA Region 4 on December 20, 2002.
12/31/02	Base case modeling completed	This was addressed in correspondence to Mr. J.I. Palmer, Regional Administrator, EPA Region 4 on December 20, 2002.
06/16/03	**Discussion of control measures**	**This was addressed in correspondence**

DATE	MILESTONE	STATUS
	being considered to EPA	**sent to Mr. J. I. Palmer, EPA Region 4 Administrator on June 13, 2003.**
10/31/03	Future case modeling	This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on December 19, 2003.
12/03	Progress report made available to EPA and public	This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on December 19, 2003.
12/31/03	Emission inventory comparison and analysis	This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on December 19, 2003.
01/31/04	One or more modeled control cases (initial)	This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on March 31, 2004.
01/31/04	Attainment maintenance analysis (initial)	This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on March 31, 2004.
03/31/04	2007 future year modeling emissions inventory	This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on March 31, 2004.
03/31/04	Final revisions to one or more modeled control cases	This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on March 31, 2004.
03/31/04	Final revisions to attainment maintenance analysis	This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on March 31, 2004.
03/31/04	**Final local early action plan submitted to DHEC; copy to EPA**	**This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on March 31, 2004.**
06/04	Progress report made available to EPA and public	This was addressed in correspondence sent to Mr. J. I. Palmer, EPA Region 4 Administrator on June 29, 2004.
12/31/04	**Early Action State Implementation Plan submitted to EPA for incorporation into SIP**	**Draft EAC SIP submitted to EPA on October 22, 2004.**
04/01/05	**Local/State control strategies needed to demonstrate attainment implemented no later than this date**	**Updates will be provided at the time of this milestone.**
09/30/05	**EPA takes final action on SIP submitted December 31, 2004**	**EPA Action.**
06/30/06	**State submits progress report**	**Updates will be provided at the time of**

DATE	MILESTONE	STATUS
	to EPA	**this milestone.**
12/31/07	**Attainment of the 8-hour ozone standard**	**Updates will be provided at the time of this milestone.**

Attachment B

Emissions Inventories

B.1. Emissions Inventories

This section discusses the development of the base-year emission inventory for the May 1998 modeling episode period and the future year emission inventory for the 2007 future period.

The Department has chosen to use 1998 emissions data for the most current year instead of 1999 data. There are two reasons for this choice. First, the 1998 inventory is considered more representative and conservative than the 1999 emissions inventory. When compared with 1998 emissions, the 1999 emissions decrease for both NO_x and VOCs. For VOCs, the reduction is 26.7%, and for NO_x the reduction is 5.3%. Second, these inventories were created prior to EPA guidance calling for 1999 or later emissions data to be used. If these inventories were recreated using 1999 data, South Carolina would likely not be able to meet the deadlines for completion of the modeling and would face a tremendous financial cost in developing the new inventories. Substantial resources were expended to get the 1998 emission inventories to their current status and a change would have been a poor financial choice given the minimal benefit using later data would provide. Appendix 14 contains letters sent to EPA providing additional information concerning the selection of the 1998 inventory.

While developing the mobile source inventory to be used in the base case ozone modeling analysis, some discrepancies were noted. When comparing EPA's 1999 National Emissions Inventory (NEI) version 2 emissions data to the 1998 emissions generated by South Carolina to be used in ozone modeling, it was found that the 1999 NEI data were almost 20% higher for on-road mobile daily NO_x emissions. This seemed very high, especially compared to the little difference from the other sources of NO_x and also from CO and VOC. This issue was investigated further to see what might be causing this large difference. A sort of the on-road mobile NO_x emissions in the NEI data tables revealed that some of the smaller population counties in the state were near the top for NO_x emissions. Most of the higher NO_x emissions came from light duty gas vehicles (LDGV) on rural interstates. Further investigation indicated the method used for allocating vehicle miles traveled (VMT) to the county and road type levels was causing the differences in NO_x emissions. The total annual statewide VMT used in the 1999 NEI and in the SC 1998 ozone modeling study are very similar. SC used 1998 annual VMT by county and road type, collected by the South Carolina Department of Transportation (SCDOT). These numbers are based on actual road studies by the SCDOT. The 1999 NEI VMT starts out with SCDOT annual VMT, which is reported to the Federal Highway Administration (FHWA) who enter the data in the Highway Performance Management System (HPMS). EPA takes this annual number and allocates it temporally by county and road type, using different allocation factors. According to Laurel Driver of the EPA's Office of Air Quality Planning and Standards (EPA-OAQPS), the contractor for the 1999 NEI allocated the VMT data to rural interstates using the actual miles of rural interstate in each county. Distributing the VMT in this manner resulted in more VMT being put on rural interstates than what the actual road count data indicated in 1998. Rural interstates typically have a higher emission factor than the other road types because of the high speeds. This explains much of the difference between the two years'

emissions. In summary, the 1998 on-road mobile emissions were calculated using actual 1998 VMT, and the 1999 NEI v.2 on-road mobile emissions were calculated with VMT data generated by the use of multiple allocation factors. Using actual VMT data is more representative than using VMT developed by allocation factors.

B.2. Base Year Inventory

A 1998 emissions inventory was developed for use as the current year emissions inventory. The emission-processing tools used in preparing the inventory are EPA's Urban Airshed Model (UAM) Emission Preprocessor System Version 2.5 (EPS 2.5), MOBILE 6, NONROAD and BEIS-2.

The modeling inventories for the episode were prepared based on the following information:

- 1996 National Emissions Trend (NET) Version 3 emission inventory.
- Emissions data provided by states for specific years.
- Episode-specific emissions data provided by individual facilities.

The 1996 NET inventory includes annual and ozone season daily emissions for oxides of nitrogen (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter with a diameter less than 10 and 2.5 microns (PM_{10} and $PM_{2.5}$), and ammonia (NH_3). Since the modeling inventories were prepared for use in ozone modeling applications, the ozone season daily emissions of NO_x, VOC, and CO from NET 96 were used for the modeling analysis.

To facilitate development of the detailed emission inventories required for photochemical modeling for this analysis, EPA's UAM Emission Preprocessor System, Version 2.5 (EPS 2.5) was used. This system, developed by Systems Applications International (SAI) under the sponsorship of the EPA's Office of Air Quality Planning and Standards, consists of series of computer programs designed to perform the intensive data manipulation necessary to adapt a county-level annual or seasonal emission inventory for modeling use. EPS 2.5 provides the capabilities and allows for the evaluation of proposed control measures for meeting Reasonable Further Progress (RFP) regulations and special study concerns.

Area source emissions for the states included in the modeling domain were generated based on the 1996 NET Version 3 emission inventory, with three exceptions. Data for the following areas were provided by their respective states, and supplemented by 1996 NET Version 3 data for source categories not available in state data:

- 1998 county-level emissions for South Carolina.
- 1996 county-level emissions for Mississippi.
- 1999 county-level emissions for Hamilton and Davidson, Tennessee.

County-level emission estimates for the majority of non-road mobile source emissions were developed using EPA's draft NONROAD model (June 2000 version) with the May maximum, minimum and average temperatures by state (provided by EPA's "National Air Pollutant Emission Trends, Procedures Document for 1990-1996"). Aircraft, commercial marine vessels, and locomotives were not included in the NONROAD model, and the emissions for those categories were taken from the 1996 NET database. The 1999 county-level aircraft emissions provided by the Department were also incorporated in the inventory.

The on-road mobile source emissions were prepared using MOBILE6 and county-level daily vehicle miles traveled (VMT) data for the states of South Carolina, North Carolina, Georgia and Tennessee. The 1996 NET Version 3 on-road mobile emissions were used for the other states within the modeling domain.

For the other states, the on-road mobile source emissions were generated based on the 1996 NET Version 3 data. The growth and adjustment factors developed by Department of Civil and Environmental Engineering, University of Tennessee were applied to the NET 96 data to project emissions from the 1996 MOBILE 5b level to the 1998 MOBILE 6 level.

The point source emission inventory was prepared based on emissions provided by the states of Alabama, Mississippi, South Carolina, North Carolina, and Tennessee. Emissions for the other states were based on the NET 96 Version 3 data base. Southern Company and the utilities in South and North Carolina provided episode-specific point source emissions.

B.3. Future Year Inventory

The projection of a base year emission inventory to a future year requires the use of economic growth factors. These are applied to the various industrial sectors and source categories to reflect expected future growth (or decline) in industrial activity and resulting emissions. There are five sets of factors available for use in projecting emission inventories for modeling. The Bureau of Economic Analysis (BEA) provides three such sets, while another two sets are available in EPA's Economic Growth Analysis System (EGAS). For ozone SIP modeling exercises, EPA guidance does not state a preference of which set to use, but does recommend that local growth information be considered in the selection and use of such factors. The BEA projection series provides state-level personal earnings, employment, and gross state product (GSP - value added) data for selected years through the year 2045, and the projection factors are available at 2-digit SIC code level for point sources and 4-digit Aerometric Information Retrieval System (AIRS) Source Category (ASC) code level for area sources. The latest set of growth factors provided by BEA was issued in 1995; BEA no longer publishes growth factors. The EGAS system includes both BEA factors and two other sets of growth factors that purportedly provide more detailed information geographically and by source category. The EGAS provides the county-level growth factors for area sources at the 10-digit ASC code level, and growth factors for point sources at the 2-digit SIC code level with

associated fuel type or 8-digit SCC code. The two sets of factors provided by EGAS are from the Bureau of Labor Statistics (BLS) and from Wharton Econometric Forecasting Associates (WEFA). Although the EGAS system purports to provide growth factors by county, for the State of South Carolina and all other surrounding states, all of the factors contained in the latest version of EGAS are the same for all counties within each state – there are no county-to-county differences.

For the South Carolina EAC modeling analysis, the future-year emission inventories for 2007, 2012, and 2017 were developed using economic growth factors provided by the BEA. Specifically, the state-specific Gross State Product (GSP) factors were used for South Carolina and all other states within the modeling domain. The selection of the BEA factors was not based on any assessment of the quality or accuracy of BEA vs. EGAS. EPA guidance does recommend that value added projections be used, and BEA's GSP factors are a measure of value added and a more complete measure of growth than BEA's earnings factors, which are only one component of GSP. The BEA GSP factors have been used recently by EPA in ozone and particulate matter modeling conducted to support national rulemaking for the Tier 2 engine and fuel sulfur standards, the non-road diesel engine rulemaking, Clear Skies, and most recently, in the Clean Air Interstate Rule (CAIR) modeling analysis.

The future-year growth estimates for area sources were based on BEA projections of GSP for all states. The BEA projections were applied at the 4-digit AIRS Source Category (ASC) level for area sources, and represent growth between the base year and future year of 2007.

For area sources with fuel combustion, energy adjustment factors which were developed from the Department of Energy (DOE) publication "Annual Energy Outlook 1999," were applied to the baseline emissions to account for increases in fuel and process efficiency in 2007, 2012, and 2017.

VOC controls were applied to area sources using information provided by EPA. The controls include federal initiatives, such as VOC content limits for consumer solvents; Title III maximum achievable control technology (MACT) assumptions; and Title I reasonably available control technology (RACT) assumptions that were not applied in the 1998 base year inventory.

Future-year growth estimates were provided by the electric utilities located North Carolina and South Carolina along with Southern Company and Tennessee Valley Authority (TVA). The future-year growth estimates for all other point sources located in the domain were based on BEA GSP projections. The BEA projections were applied at the 2-digit Standard Industrial Classification (SIC) level for point sources, and represent growth between the base year and future year of 2007.

For fuel combustion sources, energy adjustment factors which were developed from DOE publication "Annual Energy Outlook 1999," were applied to the baseline emissions to account for increases in fuel and process efficiency in 2007.

The Clean Air Act (CAA) controls include federal initiatives that were applied to the non-utility point sources. In addition, MACT controls for NO_x and VOC were applied to the non-utilities.

The emission controls required by the EPA's Regional NO_x SIP Call were emulated for the point sources located in the modeling domain covered by the SIP Call, i.e., the States of Alabama, Georgia, Illinois, Indiana, Kentucky, Maryland, Missouri, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia. The NO_x SIP Call controls were applied to the point sources located north of the 32-degree latitude line in the states of Alabama and Georgia.

County-level emission estimates for the majority of non-road mobile source emissions were developed using EPA's draft NONROAD2002 model with May maximum, minimum, and average temperatures by state as provided in EPA's "National Air Pollutant Emission Trends, Procedures Document for 1990-1996."

Emissions of aircraft, commercial marine vessels, and locomotives were projected from 1996 levels to future year levels using the BEA GSP growth factors.

The on-road mobile source emissions were prepared using MOBILE6. Future year emissions estimates from MOBILE6 include benefits from EPA's Tier II standards and low sulfur fuels. Data were provided by the States of Alabama, Georgia, South Carolina, North Carolina, and Tennessee, and used for 2007. For the other states, the on-road mobile source emissions were prepared using MOBILE6 and state-level 2007/2012/2017 VMT data provided by FHWA. The state-level VMT data were distributed to the county-level using the 2000 Census population as a surrogate.

Additional information on the development of the emissions inventories may be found in the 8-hour Ozone Modeling Technical Support Document (Appendix 5).

Attachment C

Modeling

C. Modeling

The South Carolina 8-hour ozone modeling study was initiated in January 2000 and was designed to provide technical information relevant to attainment of an 8-hour National Ambient Air Quality Standard (NAAQS) for ozone in South Carolina, with emphasis on the Anderson/Greenville/Spartanburg, Aiken/Augusta, Columbia, Florence/Darlington, and Rock Hill areas.

The technical support document uses a different naming convention for the modeled areas. The correlation between the Early Action Compact area name and the modeled area name are shown in Table C-1.

Table C-1.
Naming convention for EAC Areas to modeled areas.

EAC Area	Modeled Area
Appalachian	Anderson/Greenville/Spartanburg
Catawba	Rock Hill
Pee Dee	Darlington/Florence
Waccamaw	Coastal Sites
Santee Lynches	Not Applicable
Berkeley, Charleston, Dorchester	Coastal Sites
Low Country	Coastal Sites
Lower Savannah	Aiken/Augusta
Central Midlands	Columbia
Upper Savannah	Anderson/Greenville/Spartanburg

The draft attainment demonstration procedures for 8-hour ozone differ from those for 1-hour ozone in several ways. A key difference is that the modeled attainment test is based on relative, rather than absolute, use of the modeling results. Thus, the test relies on the ability of the photochemical modeling system to simulate the change in ozone due to emissions reductions, but not necessarily its ability to simulate exact values for future-year ozone concentrations. Another difference is that the 8-hour attainment test is site-specific while the 1-hour test focuses on an urban-scale modeling domain. For 8-hour analysis, areas of the domain that are not monitoring sites are only considered as part of a "screening" test.

For a monitoring site to pass the attainment test, its future-year estimated design value must not exceed 84 ppb. Future-year estimated design values (EDVs) are calculated for each site, for each simulated day, using "current-year" design values and relative reduction factors (RRFs) derived from future-year and base-year modeling results. The current-year design value for a given site is the three-year average of the annual fourth highest measured 8-hour ozone concentration. The RRF is the ratio of future- to base-year 8-hour maximum ozone concentrations in the vicinity of that monitoring site. The EDV is obtained by multiplying the current-year design value by the RRF.

Maximum current and estimated design values for sites in South Carolina are given in Table C-2 (A, B, and C). This table shows the calculations of the relative reduction factors for 2007. For the Anderson/Greenville/Spartanburg area, these sites are the Powdersville monitor located in Anderson County and the North Spartanburg Fire Station monitor located in Spartanburg County. For the Columbia area this site is the Sandhill monitor located in Richland County. Table C-3 contains the maximum current and estimated design values for all of the monitoring sites in South Carolina. These monitors are grouped by geographic area. The calculation process for the relative reduction factor is the same as used in Table C-2 (A, B, and C). The EDV was calculated using the 2007 future year baseline as the basis for calculation of the RRF. For all sites, the EDV for 2007 is lower than the 1997-1999 DV. In addition, the values for all sites are less than or equal to 84 ppb. The 2001-2003 design value for these sites is also included in the table; the 2001-2003 design value was the data used to determine South Carolina's 8-hour ozone attainment status. The monitors indicating nonattainment based on 2001-2003 design values are shaded.

Table C-2a.
Simulated current and future year 8-hour ozone concentrations for the Powdersville (Anderson County) site for the Anderson/Greenville/Spartanburg area.

Simulation Date	Simulated Maximum 8-Hour Ozone (ppb)	
	1998	2007
5/18/98	79	68
5/19/98	76	68
5/20/98	82	69
5/21/98	71	60
5/22/98	72	65
5/23/98	70	66
Average	75	66
EDV Calculations		
RRF		0.88
1997-1999 DV		96
2001-2003 DV		86
EDV (1999)		84

Table C-2b.
Simulated current and future year 8-hour ozone concentrations for the North Spartanburg Fire Station (Spartanburg County) site for the Anderson/Greenville/Spartanburg area.

Simulation Date	Simulated Maximum 8-Hour Ozone (ppb)	
	1998	2007
5/18/98	78	69
5/19/98	77	66
5/20/98	82	70
5/21/98	76	64
5/22/98	74	70
5/23/98	72	67
Average	76	67
EDV Calculations		
RRF		0.88
1997-1999 DV		93
2001-2003 DV		87
EDV (1999)		82

Table C-2c.
Simulated current and future year 8-hour ozone concentrations for the Sandhill (Richland County) site for the Columbia area.

Simulation Date	Simulated Maximum 8-Hour Ozone (ppb)	
	1998	2007
5/18/98	60[1]	60[1]
5/19/98	90	77
5/20/98	81	69
5/21/98	78	65
5/22/98	81	68
5/23/98	73	72
Average	80	70
EDV Calculations		
RRF		0.88
1997-1999 DV		91
2001-2003 DV		88
EDV (1999)		80

[1] Since the 5/18/98 maximum ozone concentration is less than 70 ppb, this day's ozone concentrations are not used in the calculation of the RRF.

Table C-3.
1997-1999, 2001-2003 8-hour ozone design values and 2007 estimated ozone design values for South Carolina ozone monitors.

Area/County	Monitor Name	1997-1999 Design Value (ppb)	2001-2003 Design Value (ppb)	2007 Estimated Design Value (ppb)
Aiken/Augusta				
Aiken	Jackson	89	81	73
Barnwell	Barnwell	88	78	71
Edgefield	Trenton	86	80	72
Richmond, GA	Augusta	92	83	77
Anderson/Greenville/Spartanburg Area				
Abbeville	Due West	87	82	78
Anderson	Powdersville	96	86	84
Cherokee	Cowpens	91	84	81
Oconee	Long Creek	87	84	74
Pickens	Clemson	91	84	81
Spartanburg	N. Spartanburg Fire Station	93	87	82
Union	Delta	83	81	74
Columbia Area				
Richland	Parklane	89	80	79
Richland	Sandhill	91	88	80
Richland	Congaree Bluff	72	77	65[1]
Darlington/Florence Area				
Darlington	Pee Dee	88	82	77
Rock Hill Area				
Chester	Chester	92	84	83
York	York	87	84	78
Coastal Sites				
Berkeley	Bushy Park	79	72	70
Charleston	Army Reserve	76	71	66
Charleston	Cape Romain	80	72	71
Colleton	Ashton	83	77	68

Area/County	Monitor Name	1997-1999 Design Value (ppb)	2001-2003 Design Value (ppb)	2007 Estimated Design Value (ppb)
Williamsburg	Indiantown	75	71	62

[1] Since the Congaree Bluff design value for 2001-2003 is higher than the 1997-1999 design value, the 2001-2003 design value was used in the estimated design value calculation for 2007.

A screening test was also performed for areas within South Carolina. The purpose of the screening test is to identify areas within the modeling domain that have high simulated ozone levels but that are not near a monitor. Once identified, these areas are considered in the analyses of future year attainment.

The screening test is intended as an accompaniment to the attainment test and is specifically applied to areas in the domain where the simulated base-case maximum 8-hour ozone concentrations are consistently greater than any in the vicinity of a monitoring site. EPA guidance defines "consistently" to require 50 percent or more of the simulation days, and "greater than" as more than 5 percent higher. Thus, the screening test is designed to be applied to an array of grid cells where the simulated maximum 8-hour ozone concentrations are more than 5 percent higher than any near a monitored location, on 50 percent or more of the simulation days. The screening test procedures are otherwise identical to the attainment test procedures; the current-year design value for the unmonitored area is set equal to the maximum value at any site.

No candidate grid cells for application of the test were identified. Thus, the screening test is passed and there is no need to designate additional areas in which to estimate a future design value.

The 2007 future-year baseline simulation was used as the basis for emissions-based sensitivity simulations. The sensitivity runs modeled changes in anthropogenic NO_x and VOC emissions to assess the modeling system's sensitivity to changes in emissions. SCDHEC performed eight sensitivity runs consisting of the following:

- 15 percent reduction in NO_x emissions
- 35 percent reduction in NO_x emissions
- 15 percent reduction in VOC emissions
- 35 percent reduction in VOC emissions
- 15 percent reduction in both NO_x and VOC emissions
- 35 percent reduction in both NO_x and VOC emissions
- 35 percent reduction in NO_x emissions, 15 percent reduction in VOC emissions
- 15 percent reduction in NO_x emissions, 35 percent reduction in VOC emissions

Summary

Application of the modeled attainment test indicates that:

- The average estimated design value (EDV) for 2007 is approximately 10 ppb lower than the 1997-1999 observation-based design value.
- 2007 EDVs for all sites are less than or equal to 84 ppb.
- The attainment test is passed for all sites for the 2007 scenario.

Application of the screening test indicates that:

- There are no ozone "hot spots" within the state that fall outside of the monitoring network, based on the simulation results for the May 1998 modeling episode period.

The emissions sensitivity runs for NO_x and VOC indicate that:

- South Carolina ozone production is sensitive to changes in NO_x emissions. Additional reductions in NO_x emissions should have more impact on ozone production than additional reductions in VOC emissions.
- There are no additive or synergistic effects from combined reductions of NO_x and VOC. In isolated cases there are ozone disbenefits from combined reductions of anthropogenic NO_x and VOC.

Additional information on South Carolina's ozone modeling is available in Appendices 3, 4, and 5. These appendices contain the executive summary, modeling protocol, and technical report summarizing the methods and results of the photochemical modeling application for South Carolina. The modeling effort included the application of the variable-grid Urban Airshed Model (UAM-V) photochemical modeling system for one multi-day simulation period, evaluation of model performance, and use of the modeling system to estimate ozone concentrations for 2007, 2012, and 2017.

Attachment D

Control Strategies

D.1. South Carolina's EAC Control Strategies

The modeling analysis demonstrates that all monitors in South Carolina will be attaining the 8-hour standard without the inclusion of measures beyond the national and regional programs already finalized. The *Protocol for Early Action Compacts* states that "after all Federal and State controls that have been or will be implemented by December 31, 2007, are accounted for in the modeling, the local area will identify additional local controls, as necessary, to demonstrate attainment of the 8-hour ozone standard on or before December 31, 2007." While additional control measures from local areas were not needed to attain the 8-hour ozone standard by December 31, 2007, the State and local areas continued to move forward to develop strategies to reduce emissions in South Carolina to demonstrate their commitment to the process.

The EAC process encourages state and local areas to design strategies that are tailored to their specific needs. As part of the EAC process, the Department began meeting in 2002, with local governments, industry representatives, environmental groups, and other state and federal agencies in an effort to develop state and local control strategies to reduce ozone precursors as part of the commitments under the compacts. The Department tackled these requirements from many different perspectives. First, the Department met regularly with the local EAC areas to consult with them and provide them with assistance on developing their local plans. Second, the Department formed stakeholder groups and conducted monthly meetings in an effort to develop state-wide regulations to achieve additional reductions in ozone precursors to support the EAC process. In addition, the Department worked with several major NO_x emission sources in critical areas to seek agreements for additional source specific NO_x reductions. Also, in an effort to garner further support for the process from the state legislature and other state agencies, the Department worked successfully to get a concurrent resolution passed endorsing the process. This resolution was signed by Governor Sanford on May 14, 2003, and provides for the establishment of an intergovernmental workgroup for the purpose of promoting behaviors and policies to reduce air pollution in this state. Finally, the Department has conducted interagency meetings between air quality and transportation officials to develop a Smart Highways checklist to be used in transportation planning.

The Department believes that the sum of all these efforts will have a very real and positive impact on the health and environment of South Carolina. The EAC process has allowed the state of South Carolina to achieve reductions in ozone precursors from a variety of sources that otherwise would not have occurred and this was all done on a timeframe that was sooner than what would be required through the traditional nonattainment designation process. In addition, as a result of the local EAC plans and local efforts, awareness of air quality issues has been raised to a level that would not have been possible without the EAC process. People from around the state, who have never previously had any significant exposure to air quality issues, have participated in the EAC process and helped make decisions about improving air quality. This is perhaps, above all else, the reason why the South Carolina Wildlife Federation chose to honor the "SCDHEC Early Action Compact SIP" with their 2005 South Carolina Wildlife Federation Air Conservation Award, an award that has only been bestowed six times since 1970 (see Appendix 15).

D.2. Local EAC Plans

Forty-five of forty-six counties in South Carolina have signed EACs with the Department and the EPA Region 4 office. These counties were grouped into the following ten separate areas:

Appalachian: Anderson, Cherokee, Greenville, Oconee, Pickens, Spartanburg
Catawba: Chester, Lancaster, Union, York
Pee Dee: Chesterfield, Darlington, Dillon, Florence, Marion, Marlboro
Waccamaw: Georgetown, Horry, Williamsburg
Santee Lynches: Clarendon, Kershaw, Lee, Sumter
Berkeley-Charleston-Dorchester: Berkeley, Charleston, Dorchester
Low Country: Beaufort, Colleton, Hampton, Jasper
Lower Savannah: Aiken, Allendale, Bamberg, Barnwell, Calhoun, Orangeburg
Central Midlands: Fairfield, Lexington, Newberry, Richland
Upper Savannah: Abbeville, Edgefield, Greenwood, Laurens, Saluda

For continued participation in this process, the EACs include milestones that must be met. To date, the participating areas have met all of the milestones required by their EACs. See Attachment A for further discussion regarding milestones and reporting requirements. As a result of theses areas meeting all of the milestones, EPA proposed in the Federal Register, December 16, 2003, that when it promulgated the designations for certain areas of the country not meeting the 8-hour ozone standard, EPA will issue the first of three deferrals of the effective date of the designation for any EAC area that is designated nonattainment and continues to meet all compact milestones. As stated in the Federal Register, the EPA believes this program provides an incentive for early planning, early implementation and early reductions of emissions leading to expeditious attainment and maintenance of the 8-hour ozone standard. The EPA also noted that the EACs give local areas the flexibility to develop their own approach to meeting the 8-hour ozone standard. On April 30, 2004, with an effective date of June 15, 2005, EPA issued the air quality designations and classifications for areas for the 8-hour ozone standard. In this rulemaking, EPA also promulgated the first deferral of the effective date, to September 30, 2005, for the nonattainment designation for EAC areas that have met all milestones through March 31, 2004.

Again, because the modeling shows attainment with the 8-hour ozone standard by December 2007, and maintenance through 2012 and 2017, further reductions local control strategies are not necessary. For the most part, the local strategies being implemented are voluntary, and therefore the reductions from these efforts are considered "directionally sound" and will not be quantified for use in support of modeling assumptions. Local strategies that are enforceable will be enforced by the local government.

Addendums for the Early Action Plans submitted in March 2004, by Anderson, Greenville, Lexington, Richland, and Spartanburg Counties have also been included in Appendix 8. After additional consideration of the emission reduction efforts submitted in March 2004, these counties elected to include additional reduction efforts in their local Early Action Plans to be submitted as a part of the Early Action SIP. The addendums clearly identify and describe measures the local government is committed to implement through the adoption of a county policy. While these measures have been identified, they are directionally sound, but not easily quantifiable. The emissions reduction benefits include promoting healthy lifestyle and quality of life. Examples include reductions in vehicle miles traveled (VMT) (i.e., carpooling, flex-scheduling); reduction in fuel consumption and/or cleaner fleets (i.e., idling restrictions, alternative fuels, alternative fuel vehicles or hybrids); energy conservation; and outreach efforts (i.e., notification of Ozone Action Days; ensure county residents aware of State restrictions on outdoor burning; implementing open burning ban within the county). A complete copy of each of the local plans and the addendums is included as Appendix 8. Additionally, Appendix 16 includes county level emission reductions and descriptions for the ozone EAC areas.

To date many EAC areas have begun to seek help and support from the Department's Bureau of Air Quality with their outreach initiatives to citizens in their areas. Many have identified a person on staff at the county level to receive the ground-level ozone forecast provided by the Bureau. This forecast is further distributed by this contact to others in the county to increase awareness of ground-level ozone concentrations and to take appropriate measures to protect their health. This past forecast season a toll-free line was added to help those persons without internet access the ability to call in to hear the forecast message for their area.

Department staff has met with several EAC representatives to learn of specific outreach needs in their areas. Resource tools were shared, including materials from EPA's "It All Adds Up to Cleaner Air," which Bureau staff tailored to these local areas. Furthermore, utilizing the Department's art department, radio public service announcements have been developed for several of the EAC areas to help increase awareness of ground-level ozone issues.

To build upon the awareness activities in the EAC areas, more focused efforts are being undertaken by staff to help assist and support these local efforts. For example, the Bureau's alternative commute project, "Take a Break from the Exhaust," has been packaged to enable local businesses and governments to implement with their employees. Some businesses and local county government representatives have already contacted our staff to request utilizing this project with employees. Specific values for emission reductions from this activity can be found in Appendix 16.

Another example of the active role local staff are taking is with the increased number of gas can exchange events that are occurring in the state. The Department has assisted numerous EAC contacts with planning and implementing these events. Events have been held in Greenville, Richland, Lexington, Greenwood, and York counties. This type of event has yielded tangible results for the contacts based on the number of old cans

collected and the number of newer, more environmentally safe cans distributed. The partnerships established with the private sector to purchase the newer gas cans has been a huge reason for the success of these events. Local industry partners have contributed funds to secure these cans, which have been utilized in events in several areas including the counties of Greenville, Lexington and Richland. Specific values for emission reductions from this activity can be found in Appendix 16.

The increase in efforts for improving the publics' awareness of ground-level ozone issues by the EACs has helped to support efforts to implement these types of activities for encouraging citizens to do their part to "Help Spare the Air" in South Carolina. A key to the overall strategy in South Carolina to reach attainment for the ground-level ozone standard is to encourage our citizens to be active participants in the solution to reducing ozone pre-cursors. Based on the initial efforts at the local level, we are beginning to see progress.

D.3. State EAC Regulations

In the Spring of 2003, the Department began meeting with industry representatives, environmentalists, local governments, and other interested parties to develop state-wide regulations for the purpose of getting additional NO_x and VOC reductions to assist us with the EACs. NO_x reductions were focused on during these meetings because modeling indicates that with respect to ozone formation, NO_x is the critical pollutant. Furthermore, sensitivity analysis has demonstrated that VOC reductions have very little impact on ozone in South Carolina.

After meeting with stakeholders throughout the year, two regulations were proposed to assist with additional reductions: Regulation, 61-62.5, Standard 5.2, *Control of Oxides of Nitrogen*, and revisions to Regulation 61-62.2, *Prohibition of Open Burning*.

Regulation 61-62.5, Standard 5.2, *Control of Oxides of Nitrogen (NO_x)*, is a newly-promulgated, broad-based regulation that applies state-wide to new and existing stationary sources that emit NO_x from fuel combustion and have not undergone a best available control technology (BACT) analysis for NO_x. The regulation is designed primarily to assist with the issue of growth and is also geared toward smaller sources that fall below the applicability thresholds for prevention of significant deterioration (PSD). These are sources that, for the most part, would not otherwise be required to install NO_x controls. For new sources, the regulation requires the installation of control technology that is based on BACT standards found in the national RACT/BACT/LAER clearinghouse. For existing sources, the regulation only applies when an applicable unit replaces their burner. At this point, they will be required to replace their burner with a low burner or equivalent technology capable of achieving a 30% reduction from uncontrolled levels.

Appendix 13 provides estimated NO_x reductions that are expected as a result of this new regulation. These estimates have also been included in Appendix 16 as part of the county level emission reductions for the EAC areas. The tables in Appendix 13 are divided into

three groups (two tables provide expected NO_x from regulation 61-62.5, Standard 5.2, the third table provides reductions expected from the revisions to the open burning regulation). The first table in Appendix 13 provides estimates based on the percent reduction to be achieved for new sources. The reductions for new sources vary greatly depending on the source type. For instance, for new combined cycle natural gas turbines of less than 50 megawatts capacity will be required to install controls that will achieve the equivalent of a 94% reduction from uncontrolled levels. The control requirements will help ensure that the growth of NO_x emissions is controlled. The second table in Appendix 13 pertains to estimated reductions from existing sources. As this regulation will be triggered based on existing sources replacing their burners, it may take a number of years for these reductions to be realized. However, these estimates, based on the number of applicable sources in the inventory, indicate that when fully implemented, the regulation has the potential to reduce NO_x emissions by 2,913.51 tons per year.

It is important to note that these reductions were not used to support the modeling demonstration. Even without these additional control measures, which will apply statewide rather than just in select areas, modeling analysis indicates that all monitors will be attaining the standard by 2007. However, the reductions from these regulations are quantifiable, permanent and will ensure that South Carolina gets cleaner air sooner. For example, R.61-62.5, Standard 5.2, became effective in June of 2004. Since that date, the Department has permitted two 12.56mmBtu/hr boilers at the Oconee Memorial Hospital that were required to install low NO_x burners as a result of this regulation. These are the types of smaller sources that would otherwise not be required to install NO_x controls. Furthermore, we have received and are in the process of permitting several additional applications from facilities that will be impacted by this regulation.

The other regulation that was revised order to get additional reductions in ozone precursors as part of the EAC process was Regulation 61-62.2, *Prohibition of Open Burning*. The most significant revisions to this regulation are as follows: deleting the exception for the burning of household trash, revising the exception for the burning of construction waste, and revising the exception for fires set for the purpose of firefighter training. The burning of household trash presents health and environmental concerns for many communities. The smoke generated from these activities is a nuisance to some and a health threat to others with asthma or other respiratory problems. Furthermore, the Department spends a lot of staff time and resources responding to complaints relating to these activities. Regulation 61-62.2 had previously prohibited the burning of household waste except where other disposal options were not available. This activity is now clearly prohibited and this should provide the clarity necessary to help us enforce this restriction. With respect to the exception for the burning of construction waste, the Department has revised this provision to allow only residential construction waste to be burned and this will only be allowed if it meets the provisions of the regulation. For instance, such waste will now only be allowed to be burned outside of the ozone season (April 1 through October 30) and only if the burning is conducted at least five hundred feet from any occupied structure. Furthermore, only certain "clean" wastes are allowed to be burned. Again, the Department believes that the burning of construction waste presents health and environmental concerns for many and that prohibiting this waste from being burned will

alleviate some of these concerns and will also provide additional NO_x reductions. Finally, the exception for the purpose of firefighter training has been revised to ensure that minimum health, environmental and safety concerns are addressed. The Department intends to do a review of permanent firefighter training facilities and will evaluate non-permanent sites and require Department approval prior to a burn.

Based on the Department's 1999 emissions inventory, residential burning of household waste generates 2,379 tons of NO_x and 11,896 tons of VOCs in the state annually. As for the ban on the burning of construction waste, the data indicates that the ban on residential construction waste alone will result in annual reductions of 147 tons of NO_x and 625 tons of PM (see Appendix 13 for further information). Information on the amount of reductions to be expected from the ban on the burning of commercial construction waste is not available, but it is clear that substantial reductions in NO_x and VOCs will occur statewide starting in 2004 as a direct result of the elimination of this activity as well.

Additionally, Appendix 16 includes county level emission reductions and descriptions for the ozone EAC areas.

D.4. Memorandums of Agreement/Letter of Commitment

As part of the EAC process, several of the largest existing industrial sources in the Upstate and Midlands areas of South Carolina have voluntarily committed to reduce and/or limit their NO_x emissions. These negotiations were the direct result of the EAC process as are the NO_x reductions that will result from them. SCE& G – Wateree in Richland County is installing Selective Catalytic Reduction (SCR) on two coal-fired boilers to comply with the NO_x SIP Call and has agreed to take permit limits on these units as their commitment to the EAC process. International Paper in Richland County has agreed to take an annual allowable NO_x emission reduction of 1000 tons, facility-wide. In addition, Duke Power in Anderson County has committed to install and operate low NO_x combustion controls on two coal-fired boiler units (controls were installed in 2001 on the other boiler at the facility) and to limit the NO_x emissions from these units to an emission rate of 0.27lbs/MMBtu. This is a $7 million investment by Duke Power that will result in approximately 850 tons of NO_x reduced annually. Finally, as part of this process, Transcontinental Gas Pipeline Corporation (Transco) which operates the internal combustion engines at Station 140 in Spartanburg County, has agreed to begin early implementation of the NOx emission reductions required by Phase II of EPA's NOx SIP Call regulation. In accordance with the federal requirements, Phase II is required to be fully implemented by 2007. As part of the EAC process, Transco has begin engine overhauls and engine combustion modifications so that these NOx emission reductions can be fully implemented by December 2005, well ahead of the federal timeline. These actions by these facilities are not required by any federal or state regulation and are only being taken to demonstrate their commitment to the EAC process. Appendix 10 contains copies of these voluntary agreements.

D.5. Concurrent Resolution H.3914

The Department's commitment to meeting the 8-hour ozone standard will require a concerted effort by individuals and organizations, including other state agencies. As part of the EAC process, in 2003 the Department formed the Clean Air Initiatives for Governmental Entities (CAIGE) workgroup to help state government develop and implement a plan for reducing precursors to ground-level ozone emissions, which supports the goal of achieving "cleaner air sooner" in South Carolina. A product of the CAIGE workgroup was the submittal and subsequent adoption of a concurrent resolution (H.3914). This resolution was signed by Governor Sanford on May 14, 2003, and provides for the establishment of an intergovernmental workgroup for the purpose of promoting behaviors and policies to reduce air pollution in this state. (Appendix 11)

The Department is helping to lead an effort among state and local entities, to help our state meet the national standard for ground-level ozone. This proactive approach requires moving forward with measures that both achieve "cleaner air sooner" (i.e., prior to federal mandates being imposed) and make sense for South Carolina. State governmental agencies need to actively participate in this effort and have the opportunity to lead by example.

D.6. Smart Highways

South Carolina, as a party to the 8-hour Ozone Early Action Compact is required to submit an Early Action SIP revision by December 31, 2004. While it is understood that Transportation Conformity is not required as a part of this SIP revision, through interagency meetings, air quality and transportation officials agree on the importance of considering air quality goals in transportation planning. As a result, the parties involved in the interagency meetings developed a Smart Highways checklist to be used in transportation planning. This checklist is intended solely as an informational guideline to be used in reviewing Long Range Transportation Plans and Transportation Improvement Programs for adequacy of their documentation and will be used during long range transportation plan updates as required by 23 CFR 450.322. A copy of the Smart Highways Checklist is attached in Appendix 12. Air quality and transportation officials engaged in these interagency meetings include the Metropolitan Planning Organizations (MPOs) from the deferred nonattainment EAC areas (Anderson Area Transportation Study (ANATS), Greenville-Pickens Area Transportation Study (GPATS), Spartanburg Area Transportation Study (SPATS) and the Columbia Area Transportation Study (COATS)), the South Carolina Department of Transportation, Federal Highway Administration South Carolina Division, EPA Region 4, Federal Transit Administration, and the South Carolina Department of Health and Environmental Control.

Implementation of this process will assist deferred nonattainment areas, mentioned above, in considering air quality goals in transportation planning. Also, in the event that deferral of the effective date of the nonattainment designation is withdrawn, these areas will be fully prepared to address the full regulatory requirements of Transportation Conformity.

Parties involved include:

1. Metropolitan Planning Organizations – The MPOs were created by federal highway and transit statutes for the spending of federal highway or transit funds within the MPO boundaries and have the authority for planning, programming, and coordination of federal highway and transit investments. MPOs subject to this process are the ANATS, GPATS, SPATS and COATS.
2. South Carolina Department of Health and Environmental Control - Signatory to the 8-hour Ozone Early Action Compacts; Designated pursuant to South Carolina law and by the EPA as the state air quality planning agency and as the state administrator of the approved Air Quality Program for the State of South Carolina.
3. South Carolina Department of Transportation - Designated as the State transportation planning agency under South Carolina law to carry out the statewide transportation planning process required by Title 23 U.S.C. 135, and has the authority for planning, programming, and coordination of federal highway and transit investments in areas that are not within the MPO boundaries.
4. United States Department of Transportation - Federal Highway Administration South Carolina Division Office and the Federal Transit Administration - Agencies of the United States Department of Transportation responsible for review and approval of the conformity determinations prepared for compliance with 23 U.S.C. and 49 U.S.C., respectively.
5. Environmental Protection Agency Region 4 - Signatory to the 8-hour Ozone Early Action Compacts; Responsible for approving Early Action Compact SIP and providing comment on conformity determinations.

D.7. Contingency Planning

Transportation Conformity Memorandum Of Agreement

While contingency measures are not specifically required as a part of the EAC process, the Department offers the following as additional support to the EAC "fail-safe" provisions to ensure a seamless transition to address transportation conformity should an area be required to revert to the traditional nonattainment requirements.

The Department was required by 40 CFR Part 51 Subpart T §51.390 to amend the SIP by removing any previously applicable implementation plan transportation conformity requirements and submitting a revision to the SIP meeting the requirements of 40 CFR Part 93 Subpart A. The Department chose to develop a Memorandum of Agreement (MOA) between all required parties to satisfy the interagency consultation (federal, state, and local) process required for Transportation Conformity. As per the Clean Air Act, the parties to the MOA include the Environmental Protection Agency (EPA), U.S. Department of Transportation (USDOT), S.C. Department of Transportation (SCDOT), S.C. Department of Health and Environmental Control, Metropolitan Planning Organizations (MPOs), and any applicable transportation planning agency. The

Department included all MPO's in South Carolina as a party to the MOA. Further, the MOA is not specific for any one National Ambient Air Quality Standard (NAAQS), and may be applied to any area designated nonattainment for any NAAQS. EPA approved this SIP amendment by publication in the *Federal Register* (69 FR 4245) on January 29, 2004.

With the approval of this SIP revision, once an area in South Carolina is deemed nonattainment and is required to implement Transportation Conformity, the necessary steps regarding the consultation procedures are in place, as required. This is evident with the Rock Hill-Fort Mill Transportation Study Area (RFATS) MPO, which was designated nonattainment for the 8-hour ozone standard on April 15, 2004. In June 2004, consultation meetings following the Transportation Conformity MOA began and continue to date.

Areas in South Carolina that were designated nonattainment for the 8-hour ozone standard but had the effective date of the designation deferred as a result of the Early Action Compact are not required to implement transportation conformity (i.e. Anderson-Greenville-Spartanburg and Columbia). If at anytime the designation becomes effective, the Transportation Conformity MOA will be followed. However, in an effort to ensure that air quality goals are considered in transportation planning purposes, through interagency meetings, air quality and transportation officials agree on the importance of considering air quality goals in transportation planning. As a result, the parties involved in the interagency meetings developed a Smart Highways checklist (Appendix 12) to be used reviewing Long Range Transportation Plans and Transportation Improvement Programs for adequacy of their documentation and will be used during long range transportation plan updates as required by 23 CFR 450.322. The Transportation Conformity MOA was used as a basis for developing the Smart Highways membership, checklist and overall purpose. This ensures all parties involved that if an area is required to implement Transportation Conformity, preliminary review of the transportation plans, programs and projects will already be in place.

Attachment E

Maintenance for Growth

E.1 Maintenance for Growth

To address emissions growth for five years beyond 2007, the Department developed a 2012 emissions inventory to be used in a second future year modeling analysis. The Department also developed a 2017 emissions inventory to be used in third future year modeling analysis. These emissions inventories were developed in a manner similar to the 2007 emissions inventory as described in Attachment B. The results from the 2012 and 2017 modeling analyses are discussed below.

The draft attainment demonstration procedures for 8-hour ozone differ from those for 1-hour ozone in several ways. A key difference is that the modeled attainment test is based on relative, rather than absolute, use of the modeling results. Thus, the test relies on the ability of the photochemical modeling system to simulate the change in ozone due to emissions reductions, but not necessarily its ability to simulate exact values for future-year ozone concentrations. Another difference is that the 8-hour attainment test is site-specific while the 1-hour test focuses on an urban-scale modeling domain. For 8-hour analysis, areas of the domain that are not monitoring sites are only considered as part of a "screening" test.

For a monitoring site to pass the attainment test, its future-year estimated design value must not exceed 84 ppb. Future-year estimated design values (EDVs) are calculated for each site, for each simulated day, using "current-year" design values and relative reduction factors (RRFs) derived from future-year and base-year modeling results. The current-year design value for a given site is the three-year average of the annual fourth highest measured 8-hour ozone concentration. The RRF is the ratio of future- to base-year 8-hour maximum ozone concentrations in the vicinity of that monitoring site. The EDV is obtained by multiplying the current-year design value by the RRF.

Maximum current and estimated design values for the nonattainment sites in South Carolina are given in Table E-1 (A, B, and C). This table shows the calculations of the relative reduction factors for 2012 and 2017. For the Anderson/Greenville/Spartanburg nonattainment area, these sites are the Powdersville monitor located in Anderson County and the North Spartanburg Fire Station monitor located in Spartanburg County. For the Columbia nonattainment area this site is the Sandhill monitor located in Richland County. Table E-2 contains the maximum current and estimated design values for all of the monitoring sites in South Carolina. These monitors are grouped by geographic area. The calculation process for the relative reduction factor is the same as used in Table E-1 (A, B, and C). The EDVs were calculated using the 2012 and 2017 future year baselines as the bases for calculation of the RRF. For all sites, the EDV for 2007 is lower than the 1997-1999 DV, and the EDV for 2012 is lower than both the 1997-1999 DV and the EDV for 2007. For 2017, the EDV is lower than the EDV for 2012 for all sites except for Cape Romain. In addition, the values for all sites are less than or equal to 84 ppb. The 2001-2003 design value for these sites is also included in the table; the 2001-2003 design value was the data used to determine South Carolina's 8-hour ozone attainment status. The monitors indicating non-attainment based on 2001-2003 design values are shaded.

Table E-1a.
Simulated current and future year 8-hour ozone concentrations for the Powdersville (Anderson County) site for the Anderson/Greenville/Spartanburg area.

Simulation Date	Simulated Maximum 8-Hour Ozone (ppb)		
	1998	2012	2017
5/18/98	79	69	68
5/19/98	76	63	60
5/20/98	82	65	63
5/21/98	71	59	59
5/22/98	72	63	62
5/23/98	70	61	58
Average	75	63	61
EDV Calculations			
RRF		0.84	0.81
1997-1999 DV		96	96
2001-2003 DV		86	86
EDV (1999)		81	78

Table E-1b.
Simulated current and future year 8-hour ozone concentrations for the North Spartanburg Fire Station (Spartanburg County) site for the Anderson/Greenville/Spartanburg area.

Simulation Date	Simulated Maximum 8-Hour Ozone (ppb)		
	1998	2012	2017
5/18/98	78	69	69
5/19/98	77	64	64
5/20/98	82	67	66
5/21/98	76	63	62
5/22/98	74	68	67
5/23/98	72	65	65
Average	76	66	65
EDV Calculations			
RRF		0.87	0.86
1997-1999 DV		93	93
2001-2003 DV		87	87
EDV (1999)		81	80

Table E-1c.
Simulated current and future year 8-hour ozone concentrations for the Sandhill (Richland County) site for the Columbia area.

Simulation Date	Simulated Maximum 8-Hour Ozone (ppb)		
	1998	2012	2017
5/18/98	60[1]	58[1]	58[1]
5/19/98	90	74	73
5/20/98	81	66	64
5/21/98	78	63	62
5/22/98	81	66	66
5/23/98	73	71	70
Average	80	68	67
EDV Calculations			
RRF		0.85	0.84
1997-1999 DV		91	91
2001-2003 DV		88	88
EDV (1999)		77	76

[1] Since the 5/18/98 maximum ozone concentration is less than 70 ppb, this day's ozone concentrations are not used in the calculation of the RRF.

Table E-2.
1997-1999, 2001-2003 8-hour ozone design values and 2012 and 2017 estimated ozone design values for South Carolina ozone monitors.

Area/County	Monitor Name	1997-1999 Design Value (ppb)	2001-2003 Design Value (ppb)	2012 Estimated Design Value (ppb)	2017 Estimated Design Value (ppb)
Aiken/Augusta					
Aiken	Jackson	89	81	73	69
Barnwell	Barnwell	88	78	71	70
Edgefield	Trenton	86	80	70	67
Richmond, GA	Augusta	92		75	75
Anderson/Greenville/Spartanburg Area					
Abbeville	Due West	87	82	70	66
Anderson	Powdersville	96	86	81	78
Cherokee	Cowpens	91	84	78	76
Oconee	Long Creek	87	84	72	71
Pickens	Clemson	91	84	77	75
Spartanburg	N. Spartanburg Fire Station	93	87	81	80
Union	Delta	83	81	67	65
Columbia Area					
Richland	Parklane	89	80	77	77
Richland	Sandhill	91	88	77	76
Richland	Congaree Bluff	72	77	63[1]	62[1]
Darlington/Florence Area					
Darlington	Pee Dee	88	82	75	73
Rock Hill Area					
Chester	Chester	92	84	77	76
York	York	87	84	75	72
Coastal Sites					
Berkeley	Bushy Park	79	72	67	67
Charleston	Army Reserve	76	71	66	65
Charleston	Cape Romain	80	72	68	69
Colleton	Ashton	83	77	66	64

Area/County	Monitor Name	1997-1999 Design Value (ppb)	2001-2003 Design Value (ppb)	2012 Estimated Design Value (ppb)	2017 Estimated Design Value (ppb)
Williamsburg	Indiantown	75	71	61	60

[1] Since the Congaree Bluff design value for 2001-2003 is higher than the 1997-1999 design value, the 2001-2003 design value was used in the estimated design value calculation for 2012, and 2017.

Application of the modeled attainment test for 2012 and 2017 indicate that:

- The average EDV for 2012 is approximately 13 ppb lower than the 1997-1999 observation-based design value. The average EDV for 2017 is approximately 16 ppb lower than the 1997-1999 observation-based design value.
- 2012 and 2017 EDVs for all sites are less than or equal to 84 ppb.

The attainment test is passed for all sites for the 2007, 2012, and 2017 scenarios.

Additional information on South Carolina's ozone modeling is available in the following appendices. Appendix 3 contains the technical protocol for the modeling analysis, Appendix 4 contains the executive summary for the ozone modeling technical support document, and Appendix 5 contains the technical report summarizing the methods and results of the photochemical modeling application for South Carolina. The modeling effort included the application of the variable-grid Urban Airshed Model (UAM-V) photochemical modeling system for one multi-day simulation period, evaluation of model performance, and use of the modeling system to estimate ozone concentrations for 2007, 2012, and 2017.

E.2. Maintenance Plan

Although the EAC process does not require a maintenance plan to be submitted with the attainment demonstration, the Department intends to implement a maintenance plan similar to what is required in Section 175A of the Clean Air Act.

The following describes the commitments by the Department for the EAC maintenance plan, its update in 2015, annual tracking of both stationary and mobile sources and a continuing planning process under the Early Action Compact. These commitments are in force unless the 8-hour ozone standard is revoked in the future or is no longer deemed as the appropriate approach or the EAC process is removed. The Department believes that would happen only in the event that the U.S. Environmental Protection Agency (EPA) revises or revokes the current 8-hour ozone standard of 0.08 parts per million.

Normally, the maintenance plan is submitted after the attainment demonstration State Implementation Plan (SIP) has been submitted and implemented, typically 3 to 5 years later, depending on the actual attainment date. However, the process is different under the EAC SIP. The Department will prescribe that the EAC SIP covers not only the attainment demonstration through 2007, but also the first ten-year period of the

maintenance plan, 2007-2017, including a mid-point evaluation in 2012. As a part of this EAC SIP submittal we have included the 2007 attainment demonstration modeling, the 2012 maintenance demonstration modeling, and additional maintenance demonstration modeling for 2017.

In addition to the 10-year maintenance plan demonstration, the Department will update the maintenance plan 8 years after the area is redesignated to attainment. The updated maintenance plan will cover the 10 years following the expiration of the first 10-year period of the original maintenance plan. The Department will develop the maintenance plan for the period 2017 – 2027 on the following schedule:

1. 2013: Begin emission inventory analysis work. This start date will allow the Department to use the 2010 U.S. Census information in the emission inventory development.
2. 2015: Complete emission inventory analysis work and submit updated maintenance plan to the EPA.

The Department's maintenance plan does not include contingency measures in the EAC SIP since the provisions in the EAC SIP are to address both attainment and maintenance needs and will remain as part of the SIP throughout the attainment and 20-year maintenance periods. Further, the modeling analysis for 2012 and 2017 show a downward trend in emissions, as well as expected air quality values. The Department believes that the contingency measure adoption approach as outlined in the following Annual Tracking for Growth mechanisms is the most appropriate way to address the contingency provisions.

Annual Tracking for Growth

The EAC requires the following elements be tracked in order to ensure that the standard is maintained:

1. An annual review of growth (especially highway mobile and stationary point source) to ensure emission reduction strategies and growth assumptions are adequate;
2. Identification and quantification of federal, state, and/or local measures indicating sufficient reductions to offset growth estimates.

Stationary Point Sources

To meet the annual review of growth of stationary point sources, the Department will do the following analysis. The obligation to conduct these analyses and, where indicated, adopt and implement additional control measures based on the result of the analyses, lasts throughout the maintenance period (2027).

Beginning with the December 2005 biannual progress report, every year the Department will evaluate the most recent annual stationary source emission inventory completed by the Department. The stationary point source emission inventory for NOx will be

compared to the 1998 annual inventory used in the air quality modeling analyses for the attainment demonstration.

Highway Mobile Sources

To meet the annual review of growth in highway mobile sources, the Department will do the following analyses:

Beginning with the December 2005 biannual progress report, each year the Department will evaluate the most recent annual VMT data available. The actual annual growth rate from 1998 will be compared to the average annual growth rate used in the modeling analysis from 1998 through 2007.

Air Quality Analysis

For purposes of determining if an area has a corresponding increase in ozone, the Department will review and report each December:

- Design Value Trends – Most recent design values (3 year average of the 4th highest 8-hour ozone average), compared to the trend in design values from the 1997-1999 timeframe to present.
- 8-Hour Ozone Exceedances – Number of exceedances of the 8-hour ozone standard at each monitor in the EAC areas for the most recent ozone season, compared to the number of exceedances at each monitor from 1997 to present.
- 1-Hour Ozone Design Value Trends – Most recent 1-hour ozone design values compared to the trend in 1-hour ozone design values from the 1997-1999 timeframe to present.
- 4th Highest Value Trends – 4th Highest 1-hour ozone value compared to the 4th highest 1-hour ozone value from 1997 to present.
- 1-Hour Ozone Exceedances – Number of exceedances of the 1-hour ozone standard at each monitor in the EAC areas for the most recent ozone season, compared to the number of exceedances at each monitor from 1997 to present.
- Weather Patterns – Discussion of weather patterns and climatology in most recent ozone season.

Continuing Planning Process

In addition, the EAC protocol requires a continuing planning process, including modeling updates (if needed) and modeling assumption verification. Since the larger source sectors for NOx emissions will be covered in the annual stationary point source and highway mobile source evaluation discussed above, the Department proposes to evaluate in 2008 whether a full modeling update is needed for the EAC areas. At this point, the Department will use the full emission inventories submitted as part of the Consolidated Emissions Reporting Rule (CERR) process. Emissions will have been inventoried for calendar year 2005. These emissions will be used to evaluate whether a full modeling update is needed. These emissions can also be used to determine if a particular source

sector is growing at a higher growth rate than previously forecast, and if so, whether contingency measures should be implemented in the event the sector began causing 8-hour ozone standard violations. The State may conduct any of the above analyses and reviews on a combined area basis as appropriate to utilize resources more effectively.

General Timeline

- December 2004 – The Department submits EAC SIP, covering both attainment date of 2007 and first 10-year maintenance period through 2017
- April 2005 – The Department and EAC areas implement EAC measures
- December 2005 – First annual tracking report is submitted
- December 2006 – Second annual tracking report is submitted
- December 2007 – Attainment date
- December 2007 – Third annual tracking report is submitted
- April 2008 – EPA designates area for the 8-hour ozone standard
- December 2008 – The Department completes evaluation of new emissions data.
- December 2008 – Fourth annual tracking report is submitted and continues for each year thereafter through the end of the maintenance period
- January 2013 – The Department begins work on 10-year maintenance plan update
- December 2015 – submits 10-year maintenance plan update
- December 2027 – 20 year maintenance plan and annual tracking for growth concludes

Attachment F

Public Involvement

F. Public Involvement

A Notice of Drafting (NOD) was published in the South Carolina *State Register* on August 23, 2002, expressing the desire to pursue an early action plan that provides for ambient air in South Carolina that meets the more restrictive national standard prior to the federal deadline(s). The NOD requested those interested in participating in an early action plan for ground-level ozone provide that interest in writing to the Department. Due to the timing of events and the requirements of the State's Administrative Procedures Act, a second drafting notice was published in the *State Register* on April 25, 2003, the purpose of which was to extend the comment period.

To generate interest in this process, the Department established a large stakeholder group consisting of federal, state and local government officials, environmental groups, citizens groups, business, industry and private citizens. The initial stakeholder list, generated by staff and including those requesting to participate as a result of the NOD was submitted to EPA as a part of the June 2003 Progress Report. On August 26, 2002, correspondence was issued to stakeholders, seeking active participation in the development of an Early Action Compact (EAC) regarding ground level ozone reduction in South Carolina and providing a list of informational forums scheduled throughout the state. Copies of the correspondence and associated attachments sent to the stakeholders as well as copies of the sign-in sheets, meeting agendas and survey forms were submitted to EPA as a part of the June 2003 Progress Report. Informational forums seeking active participation in the development of an EAC were held on the following dates:

October 1, 2002 – Columbia
October 3, 2002 – Greenville
October 8, 2002 – Florence
October 10, 2002 – Rock Hill
October 15, 2002 – Aiken
October 16, 2002 - Charleston

Local stakeholder participation was obtained through the involvement of the county administrators and/or county councils. On November 12, 2002, the South Carolina Association of Counties issued correspondence to each county council chairman and county chief administrative officer stating support of each county's participation in the 8-hour ozone EAC. Also on November 12, 2002, the Department issued correspondence to county administrators seeking active stakeholders for participating in the EAC. This correspondence included a working draft copy of the EAC. As a result, Department staff participated in numerous county council meetings and other discussions (telephone and electronic mail) with county officials seeking local participation in the EAC process. Dates of these meetings were submitted to EPA as a part of the June 2003 Progress Report. On December 12, 2002, Department staff presented at the yearly meeting of county administrators sponsored by the South Carolina Association of Counties. At the request of several counties and the Association of Counties, the Department again issued

correspondence to the county's seeking participation. Copies of these correspondence were submitted to EPA as a part of the June 2003 Progress Report.

As of December 31, 2002, forty-five of the forty-six counties in South Carolina elected to become active stakeholders in the South Carolina Early Action process. In December 2002, the Department submitted to EPA the compacts signed by the respective local participant and R. Lewis Shaw the Deputy Commissioner for the Department's Environmental Quality Control. (See Appendix 2)

One condition set by EPA Region 4 for York, Chester, and Lancaster counties participating in the EAC requires that South Carolina continue to actively participate in the Charlotte Region Integrated Air Quality Management Pilot Project. This project has since been renamed "Sustainable Environment for Quality of Life" (SEQL). In addition to the milestones established in the Early Action Compact, South Carolina and North Carolina were required to develop a specific memorandum of understanding (MOU) detailing how this requirement will be met. On March 14, 2003, Mr. R. Lewis Shaw and Mr. William G. Ross, Jr., Secretary for the North Carolina Department of Environmental and Natural Resources signed the MOU. A copy of the MOU was submitted to EPA as a part of the June 2003 Progress Report.

South Carolina was not required to enter into a formal agreement with the state of Georgia in regards to emission reduction strategies for the Upper and Lower Savannah areas. However, representatives from the state of Georgia attended the Lower Savannah Council of Government meeting held on February 6, 2003. Representatives from EPA also attended this meeting. In addition, Department staff attended a meeting held on February 21, 2003, in Augusta, Georgia, with local and state government officials from Georgia and South Carolina and EPA to discuss the impact of the EAC process and emission reduction strategies for that area.

The Department held meetings in ten different areas around the state. These meetings were held at the local Council of Government (COG) office and were "kick-off" meetings with the local participating areas (i.e., county officials; COG representatives; EPA attended three; and, where applicable adjoining state representatives). Included as a part of the June 2003 Progress Report, was the correspondence issued on January 27, 2003, to the county contacts, which included resources such as the Air Quality Improvement Tools for Local Governments. The dates and locations of these meetings were:

January 27, 2003 – Santee Lynches Council of Governments
January 28, 2003 – Central Midlands Council of Governments
January 30, 2003 – Appalachian Council of Governments
February 3, 2003 – Pee Dee Council of Governments
February 4, 2003 – Upper Savannah Council of Governments
February 5, 2003 – Berkeley-Charleston-Dorchester Council of Governments
February 6, 2003 – Lower Savannah Council of Governments
February 10, 2003 – Catawba Council of Governments

February 11, 2003 – Waccamaw Council of Governments
February 13, 2003 – Low Country Council of Governments

In addition to activities related to assisting local EAC areas with the development of their local strategies, the Department worked with stakeholders to develop statewide regulations to achieve additional reductions in ozone precursors as part of the EAC process. Starting in the Spring of 2003, the Department began meeting with stakeholders representing various industries, environmental and local government groups. The stakeholders were divided into two groups. The first group was formed to review the existing Open Burning Regulation to determine possible revisions to this regulation that would assist with the EAC efforts. The second group had a broader mission which was to review existing regulations for stationary sources and also promulgate a new regulation to achieve additional reductions in ozone precursors. These groups met monthly for the remainder of 2003 and the product of these meetings was a package of regulations that were submitted to the Board of Health and Environmental Control (Board). The Board conducted a public hearing on these regulations on January 8, 2004. The regulations were then submitted to the South Carolina State Legislature in January for their review and approval.

The Department also conducted three EAC Updates that were broadcast live on the following dates: February 26, 2003, June 25, 2003, and August 18, 2004. Finally, a public hearing on the entire EAC SIP package was conducted on November 22, 2004.

Notification of these updates was provided to all stakeholders and was also included on the Department's website. The updates were held in the Peeple's Auditorium at the Department's Columbia office and were broadcast to the Department's Environmental Quality Control offices around the state. The updates provided information on the latest efforts regarding modeling, statewide regulatory changes, and emission reduction activities of the state and local areas and provided the opportunity for comment.

Throughout this process, the Department issued numerous press releases, news publications, television reports, and ozone education/outreach initiatives regarding the early action process. Specific information and appropriate copies have been and will continue to be submitted to EPA as a part of the routine progress reports, every six months.

Furthermore, the Department established a website (www.scdhec.net/baq/eap.html) for stakeholders to obtain updated information regarding the early action process. The website address was given in the initial press release (August 28, 2002) and continues to be included on correspondence and presentations. Several counties also include information on their respective website and also provide a link to the Department's website. Information regarding the individual county websites may be found in the progress reports.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

MEMORANDUM

DATE: June 13, 1989

SUBJECT: Transmittal of Background Statement on "Top-Down" Best Available Control Technology (BACT)

FROM: John Calcagni, Director
Air Quality Management Division

TO: See Below

In a number of recent meetings, it has become clear that a significant amount of confusion exists regarding the basis for top-down BACT. To assist you and your staff in answering questions in this regard, I asked my staff to prepare a paper which discusses the origins of and rationale for the policy initiative.

The paper, which was prepared in coordination with the Office of General Counsel, also explains why the Environmental Protection Agency (EPA) has adapted its current policy on BACT and clarifies EPA's view that this policy is consistent with current statutory and regulatory requirements.

If you have any questions about the background statement, please contact David Solomon of the New Source Review Section at FTS 629-5375.

Attachment

Addressees: Director, Air Management Division, Regions I, III, and IX
Director, Air & Waste Management Division, Region II
Director, Air, Pesticides, & Toxics Management Division, Region IV
Director, Air & Radiation Division, Region V
Director, Air, Pesticides, & Toxics Division, Region VI
Director, Air & Toxics Division, Regions VII, VIII, and X

BACKGROUND STATEMENT
ON THE
ENVIRONMENTAL PROTECTION AGENCY'S (EPA'S)
TOP-DOWN POLICY

I. INTRODUCTION

On December 1, 1987, former Assistant Administrator J. Craig Potter issued a memorandum establishing several program initiatives designed to improve the effectiveness of the Clean Air Act's (CAA's) new source review programs within the constraints of existing regulations. Among these initiatives was the "top-down" process for determining best available control technology (BACT) under the prevention of significant deterioration (PSD) provisions of the CAA. In brief, the top-down process requires that all available control technologies are ranked in descending order of effectiveness. The PSD applicant first examines the most stringent -- or "top" -- alternative. That alternative is established as BACT unless the applicant can demonstrate, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The December 1, 1987 memorandum directed the Office of Air Quality Planning and Standards (OAQPS) to implement many of these program initiatives, and specifically called upon OAQPS to develop guidance on the top-down process. As a consequence, that office has received numerous inquiries regarding the basis for and proper implementation of the top-down process. The OAQPS is preparing a separate summary of the top-down process. A draft of the summary is presently under review. Therefore, this statement focuses on a background discussion explaining why EPA has adopted its current policy on BACT, and clarifying EPA's view that this policy is consistent with current statutory and regulatory requirements.

II. ADMINISTRATIVE HISTORY

BACT is defined as:

> [t]he maximum degree of reduction for each pollutant *** which the [permitting authority], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable ***

Clean Air Act section 169(3), 42 U.S.C. 7479(3); 40 C.F.R. 52.21(b)(12); 40 C.F.R. 51.166(b)(12). In January 1979, EPA had disseminated "Guidelines for Determining BACT Under PSD" (OAQPS, December 1978) and in October 1980 had issued a "PSD Workshop Manual" (OAQPS, October 1980) that included more detailed guidance on BACT. Those documents described a so-called "bottom-up" approach to BACT determinations. The applicant was to propose a base case as BACT, present more stringent control alternatives, and defend its BACT selection by "demonstrating that each alternative control system ... would cause unreasonable adverse energy, environmental, or economic impacts." See 1978 BACT Guidelines at 5-6.

In June 1986, Craig Potter established a task force to address growing concerns about the effectiveness of EPA's new source review programs in carrying out their statutory responsibilities. One of the task force's findings, based upon a comprehensive review of numerous PSD permits issued during the previous several years, was that PSD applicants and States frequently were conducting inadequate BACT determinations using the "bottom-up" approach of the 1978 guidelines and the 1980 workshop manual. In numerous instances, applicants would propose an emission limitation at or near an applicable new source performance standard (NSPS) under section 111 of the CAA as the base case, and provide little or no consideration of the more stringent control options before settling on the proposed level as BACT. It also appeared that States typically would accept these determinations with little or no independent analysis, thereby possibly failing to fulfill their

responsibilities under the Act. The task force pointed out two basic solutions to the problem of inadequate BACT analyses. One was to focus on improving implementation of the bottom-up approach so that in practice as well as in theory, the statutory requirements would be observed. The other option was to call for a top-down approach to the BACT analysis in the expectation that its internal dynamics would, in practice, achieve more effective implementation of the BACT requirements. See generally, "New Source Review Task Force Report," Final Draft, December 1986, at 25-28.

In the meantime, in an adjudicative decision on appeal of a PSD permit for a municipal waste combustor (MWC), the Administrator held that a PSD applicant has the "burden of demonstrating that significant technical defects, or substantial local economic, energy, or environmental factors or other costs warrant a control technology less efficient than [the most stringent technology available]." Honolulu Resource Recovery Facility ("H-Power"), PSD Appeal No. 86-8, at 7 (Remand Order, June 22, 1987). Shortly thereafter, EPA issued guidance calling for application of the H-Power holding to all BACT determinations for MWCs. "Operational Guidance on Control Technology for New and Modified Municipal Waste Combustors (MWCs)," June 26, 1987.

In light of these events, EPA decided in the December 1, 1987 Potter memorandum that as a matter of Agency policy it would adopt the top-down BACT approach for all categories of PSD sources. Mr. Potter instructed EPA Regional Offices to use the top-down approach in their own BACT determinations, and to strongly encourage State and local PSD permitting authorities to do so as well. The Potter memorandum further directed Regional Offices to conduct timely reviews of PSD applications, and to comment adversely on proposed PSD permits that failed to adequately consider the more stringent control options, as would be required as a matter of course under a top-down approach. If final State and local permits still failed to reflect adequate consideration of the relevant BACT factors, the Regions were to consider such permits deficient. An additional point related to the Potter memorandum was that the top-down process should in practice lessen administrative burdens in the conduct of BACT determinations because it does

not require a full analysis of all control alternatives that are more stringent than the NSPS or other base case, as would be required under a proper bottom-up analysis.

III. THE TOP-DOWN APPROACH AS PART OF THE EXISTING BACT DETERMINATION PROCESS

A. The Top-Down Approach Does Not Alter Existing BACT Requirements.

In calling for use of the top-down approach, EPA has not effected a change in existing PSD regulations, and has not altered the BACT requirements for any source. The definition of BACT in the statute, EPA regulations, and State implementation plans remains the same.

Regardless of the specific methodology used for determining BACT, be it "top-down," "bottom-up," or otherwise, the same core criteria apply to any BACT analysis: the applicant must consider all available alternatives, and demonstrate why the most stringent should not be adopted. Recall, however, the New Source Review Task Force's finding that in many instances the bottom-up methodology was applied inadequately. In response, EPA has developed the top-down methodology in order to improve administration of these basic BACT selection requirements already provided for in the CAA, current PSD regulations, State implementation plans, and EPA guidance. However, the top-down methodology does not involve any change in the substance of, or fundamental procedures for, a BACT determination.

What is different about the top-down policy is the emphasis upon considering the most stringent control options first. But this does not represent a radical shift in the burden of proof from permitting authorities to PSD applicants. Instead it is intended to make more effective the core policies that appear in the 1978 guidelines. That is, the top-down approach explicitly recognizes the self-evident presumption that technologies already shown to be "available" can be used by the prospective source under consideration, and the fact that the PSD applicant is in the best position to provide an initial justification why an available technology is not

"achievable" for that particular source as well. In explicitly calling upon PSD applicants to consider the most stringent controls first, and either adopt those controls or explain why they are not achievable, EPA is only seeking to improve the administration of an existing requirement. The permitting authority after public review and comment remains responsible for exercising informed judgment in determining achievability in accordance with this requirement.

B. The Top-Down Process Is Consistent With the CAA.

The EPA believes that the top-down approach to BACT is supported by the statutory definition in section 169(3) of the CAA. The legislative history is clear that Congress intended BACT to perform a technology-forcing function. See S. Rep. No. 95-252, 95th Cong., 1st Sess. 31 (1977), reprinted in 3 A Legislative History of the CAA Amendments of 1977 at 1405; 123 Cong. Rec. S9171, 3 Legislative History at 729 (remarks of Sen. Edmund G. Muskie, principal author of 1977 Amendments). This construction was reinforced in H-Power and in a later PSD appeal decision, Pennsauken County. New Jersey Resource Recovery Facility, PSD Appeal No. 88-8 (Remand Order, Nov. 10, 1988). In those cases the Administrator interpreted the BACT definition as requiring the PSD applicant to demonstrate to the permitting authority why the most stringent control technology "available" is not "achievable" in that case. It is also clear that in adopting BACT, Congress intended PSD permitting authorities to exercise informed discretion to weigh energy, environmental, and economic impacts in determining BACT for a particular source. S. Rep. No 95-252 at 31, 3 Legislative History at 1405. In addition, in section 160 of the CAA, Congress emphasized that public participation and a careful assessment of relevant factors is crucial to all decisionmaking under the CAA's PSD provisions.

In theory, these statutory goals can be fulfilled by either a top-down or bottom-up approach to BACT determinations. However, as discussed previously, EPA's experience has been that, as implemented in practice, the bottom-up approach is deficient in actually achieving these goals, and the Agency now

believes they can best be served by the top-down BACT methodology. The EPA's policy furthers the spread of effective pollution control technologies by focusing attention first on the most stringent control options. At the same time, it provides a full opportunity for meaningful public participation, and allows permitting authorities to give informed consideration to energy, environmental, and economic impacts before reaching a final BACT decision.

C. Under The Top-Down Process, Important Distinctions Between BACT and Lowest Achievable Emission Rate (LAER) are Maintained, and States Still Weigh the Relevant Factors.

The top-down approach maintains the statutory distinctions between BACT and the LAER requirement under section 171(3) of the CAA (which major new sources and major modifications locating in nonattainment areas are required to meet). The LAER requirement provides that all affected sources must comply with either the most stringent limit contained in a State implementation plan, or the most stringent emission limitation achieved in practice, whichever is more stringent. In contrast, under BACT, consideration of energy, environmental, or economic impacts may justify a lesser degree of control in the particular case. The EPA's policy regarding the top-down process does not alter this sharp statutory distinction.

The EPA believes it is appropriate to consider LAER determinations in establishing the most stringent technology "available" -- i.e., the "top" control option -- for purposes of BACT analyses under the top-down methodology. The statute requires PSD applicants to consider the most stringent controls that are "available," and availability should be given a straightforward, practical meaning. See Pennsauken at 8. Any emission limit that has been required for LAER purposes must be "actually, not theoretically," possible. 3 Legislative History at 537. Thus, a limit contained in a LAER determination is presumably "available" for BACT purposes by any source in the same category, and is not merely experimental or otherwise beyond the bounds of consideration. This is so regardless of whether a top-down or a bottom-up approach to consideration of the control

technology in question is used. Accordingly, the fact that, to date, a technology has been required only under LAER determinations, or has not yet been applied to many sources, does not render it unavailable for BACT consideration. See Pennsauken at 8.

The top-down policy (and in particular, the use of LAER determinations to determine available BACT alternatives), does not establish a national BACT standard. The statute provides that technical considerations may, alone or in conjunction with energy, environmental, or economic factors, render a given control technology or associated emission limitation not "achievable" in a given PSD case. It is precisely the purpose of the BACT analysis to weigh these factors in determining whether an "available" technology or emission limit is "achievable" in the given case. Adoption of a top-down methodology does not change this requirement.

The EPA's policy regarding the top-down process does not prejudge the weight that permitting authorities must give to the relevant statutory factors. Instead, the purpose of EPA's policy is to insure that the relevant factors are weighed in the well-considered manner called for by Congress, and that the weighing process is properly informed by resort to objective data where appropriate. Thus, as the Administrator has held in H-Power and Pennsauken, it is not sufficient to reject a control technology by merely asserting that it is "too costly." Rather, claims that economic (or other) factors render a technology or emission limit not achievable must be supported by an analysis utilizing readily available objective indicators of adverse impacts. However, the final weighing of those factors, and the final BACT decision, are made by the permitting authority. Rejection of a control technology by a reviewing agency must have a rationale arrived at after full consideration of data determined in a consistent and sound manner. Such decisions may not be arbitrary, capricious, or contrary to law.

D. It Is Appropriate to Implement the Top-Down Process Through BACT Guidance and Adjudication.

The EPA believes it is appropriate to continue implementing its BACT policies through policy statements, and any relevant adjudicative decisions of the Administrator, rather than through rulemaking. The EPA has followed a consistent practice of issuing BACT guidance since passage of the PSD program and promulgation of BACT regulations. With respect to the top-down policy in particular, EPA's statements of policy have been informed in part by the adjudicative decisions in H-Power, Pennsauken, and North County Resource Recovery Associates, PSD Appeal No. 85-2 (Remand Order, June 3, 1986). However, like EPA's top-down policy statements, those decisions do not change the law, but at most interpret existing law. In any event, it is clear that EPA, like other regulatory agencies, has authority to create binding precedent through adjudication. See, e.g., NLRB v. Wyman-Gordon Co., 394 U.S. 759 (1969). It is also clear that, absent an explicit statutory constraint, EPA has broad discretion to employ those procedures and methods it feels are best suited to discharging its numerous and varied duties. See, e.g., Vermont Yankee Nuclear Power Corp. v. NRDC, 435 U.S. 519, 543 (1978).

IV. SUMMARY

In summary, for the reasons discussed above, the top-down process is consistent with existing statutory and regulatory requirements. The EPA does not believe that its policy views on the top-down process create any new legal rights or duties which must be implemented through rulemaking.

	July, 1983			April, 1984			June, 1984			December, 1984		
Date	Scrubber Inlet SO2 lbs/MM Btu	Stack SO2 lbs/MM Btu	% SO2 removal	Scrubber Inlet SO2 lbs/MM Btu	Stack SO2 lbs/MM Btu	% SO2 removal	Scrubber Inlet SO2 lbs/MM Btu	Stack SO2 lbs/MM Btu	% SO2 removal	Scrubber Inlet SO2 lbs/MM Btu	Stack SO2 lbs/MM Btu	% SO2 removal
1	4.41	0.017	99.61				4.24	0.003	99.93	3.30	0.011	99.67
2	4.27	0.014	99.67	4.99	0.001	99.98	4.23	0.004	99.91	3.35	0.009	99.73
3	4.77	0.014	99.71	5.45	0.002	99.96	4.09	0.003	99.93	3.27	0.01	99.69
4	4.81	0.01	99.79	4.91	0.001	99.98	3.75	0.005	99.87			
5	5.25	0.009	99.83	4.99	0.002	99.96				2.61	0.007	99.73
6	5.38	0.004	99.93	5.35	0.004	99.93				2.44	0.008	99.67
7	5.60	0.009	99.84	4.71	0.005	99.89						
8	5.66	0.012	99.79	4.42	0.005	99.89	3.68	0.001	99.97	2.38	0.007	99.71
9	5.32	0.012	99.77	4.57	0.005	99.89	3.66	0.001	99.97	2.57	0.01	99.61
10	5.26	0.012	99.77	4.98	0.006	99.88	3.73	0.001	99.97	2.79	0.012	99.57
11	5.37	0.013	99.76	4.49	0.006	99.87	3.98	0.002	99.95	2.54	0.01	99.61
12	5.44	0.016	99.71	4.56	0.008	99.82	4.23	0.004	99.91	2.66	0.011	99.59
13	5.39	0.016	99.70	4.85	0.016	99.67	3.65	0.101	97.23	2.59	0.015	99.42
14	5.13	0.016	99.69	4.45	0.007	99.84	3.91	0	100.00	2.99	0.014	99.53
15	5.10	0.017	99.67	4.45	0.005	99.89				3.19	0.014	99.56
16	5.11	0.014	99.73	4.96	0.001	99.98				2.87	0.014	99.51
17	4.45	0.011	99.75	4.50	0	100.00				2.58	0.015	99.42
18	4.81	0.012	99.75	4.65	0	100.00				2.59	0.013	99.50
19	5.01	0.014	99.72	4.62	0	100.00				2.83	0.01	99.65
20	5.07	0.014	99.72	4.53	0.002	99.96						
21	5.07	0.014	99.72	4.57	0.003	99.93				3.16	0.011	99.65
22	5.14	0.012	99.77	4.57	0.003	99.93						
23				4.51	0.002	99.96						
24	5.12	0.003	99.94	3.95	0	100.00						
25	5.27	0.003	99.94	3.87	0.011	99.72						
26	5.27	0.003	99.94	4.04	0.018	99.55						
27				4.38	0.009	99.79				2.37	0.011	99.54
28				4.44	0.004	99.91				2.19	0.015	99.32
29	5.02	0.003	99.94	4.14	0.002	99.95						
30	4.82	0.004	99.92	4.40	0.011	99.75	4.10	0	100.00			
31												
Avg.	5.086	0.011	99.78	4.597	0.005	99.89	3.938	0.010	99.72	2.764	0.011	99.58
Stan Dev		0.005	0.10		0.005	0.11		0.029	0.78		0.003	0.11
No. of days			27			29			12			20

Overall daily average inlet	4.240
Overall daily average emission	0.009
Overall daily average % removal	99.76
Total no. of days	88

Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant

#27

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ABSTRACT

Shinko-Kobe Electric Power Plant was designed as an "Urban Type Plant" which must meet stringent environmental control requirements, because this power plant is located in the center of the Kobe City. To maintain the quality of life of the citizens, Chiyoda Corporation was requested to provide process capabilities to meet very stringent environmental requirements. The CT-121 FGD process can provide superior SO_2 and particulate removal performance to meet the client's requirements as demonstrated by our experience in existing CT-121 installations.

This paper describes the commercial experience of the CT-121 plant for Shinko-Kobe Electric Power Plant from the following different perspectives.

- From operating experience:
  - Stable SO_2 removal efficiency of over 99 percent.
  - High SO_2 removal efficiency with low operating cost.
  - High particulate removal efficiency.
- From construction experience:
  - Construction cost reduction by applying the panel construction method.

In addition to the above, the relevance of CT-121 Kobe experience to North American applications is discussed from the following viewpoints.

- Accommodating a wide variety of fuels and inlet conditions.
- Maximizing the results of an investment in FGD technology.
- Avoiding costly particulate control modifications or upgrades.
- Reducing project costs and cost variance through panel construction of the JBR.

INTRODUCTION

Shinko-Kobe Electric Power Plant is located in the center of Kobe City, which is the fifth largest city in Japan with a population of over one million, and is the largest IPP project in Japan.

The CT-121 FGD process was requested to provide process capabilities which meet the unprecedented and stringent environmental requirements imposed by the site-specific condition.

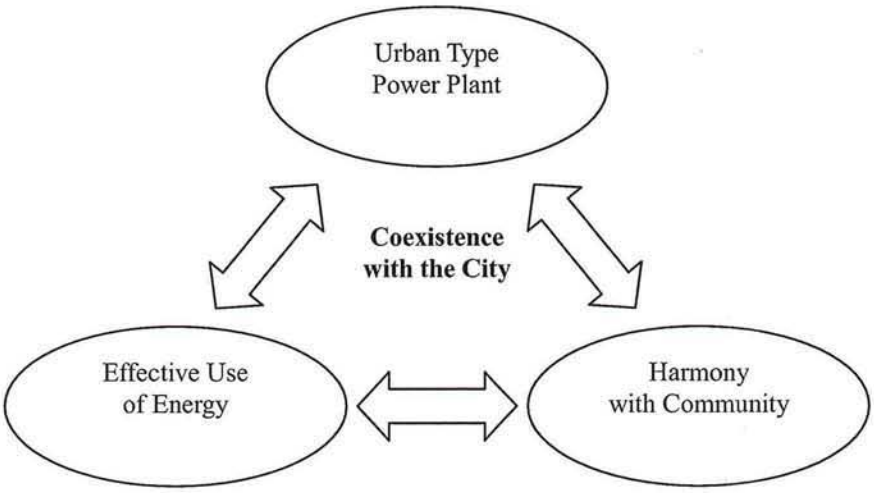
To maintain the quality of life of the citizens, Shinko-Kobe Electric Power Plant has set up a noble theme. The CT-121 must also play an important role to realize the theme through its design and construction.

THEME OF SHINKO-KOBE ELECTRIC POWER PLANT

Shinko-Kobe Electric Power Plant (coal fired power generation, 2 x 700MW) has been constructed as an "Urban Type Power Plant" under the theme of coexistence with the City. The No. 1 power plant was put into operation on April 1, 2002, and the No. 2 power plant is now under construction for commercial operation starting on April 1, 2004.

Figure 1 illustrates the theme of Shinko-Kobe Electric Power Plant.

Figure 1 Theme of Shinko-Kobe Electric Power Plant



PROPOSITION REQUESTED OF THE CT-121 TO MAINTAIN QUALITY OF LIFE OF CITIZENS

To achieve the noble theme and to maintain the quality of life of the citizens, Shinko-Kobe Power Plant has introduced the latest environmental technologies of the highest level from all fields including air pollution, water quality preservation, noise, vibration and odor prevention.

In the field of air pollution control, the CT-121 can strongly boast its SO_2 and particulate removal capability to meet the client's requirements. That is to say, it can realize a part of the theme established by Shinko-Kobe Electric Power Plant and can play an important role in an "Urban Type Power Plant".

The propositions requested of the CT-121 are summarized as follows:

- Stable SO_2 removal efficiency of over 99 percent.
- High SO_2 removal efficiency with low operating cost.
- High particulate removal efficiency.

PROPOSITIONS FROM THE OPERATING EXPERIENCE

The No.1 FGD unit of the CT-121 installations for Shinko-Kobe Electric Power Plant, which is hereinafter referred to as "CT-121 Kobe," has been operated for almost a year without any trouble.

This chapter describes the operating experience of CT-121 Kobe.

Stable SO_2 Removal Efficiency of Over 99 Percent

The outline of Shinko-Kobe Electric Power Plant and the basic design of the CT-121 Kobe are shown in Table 1 and Table 2, respectively.

Table 1
Outline of Shinko-Kobe Electric Power Plant

Location	Kobe City, Hyogo, Japan
Output	700MW (×2)
Fuel	Coal (S in coal: 0.93 %, HHV: 10,400 Btu/lb)
Boiler	Once-through boiler
Steam Turbine	Condensing turbine
Generator	Synchronous generator
Flue Gas Treatment	・DeNOx System : SCR process
	・Dust collector : Low-low temperature ESP
	・DeSOx system : The CT-121 Process
Construction Started	June 1, 1999
Commercial Operation started	April 1, 2002

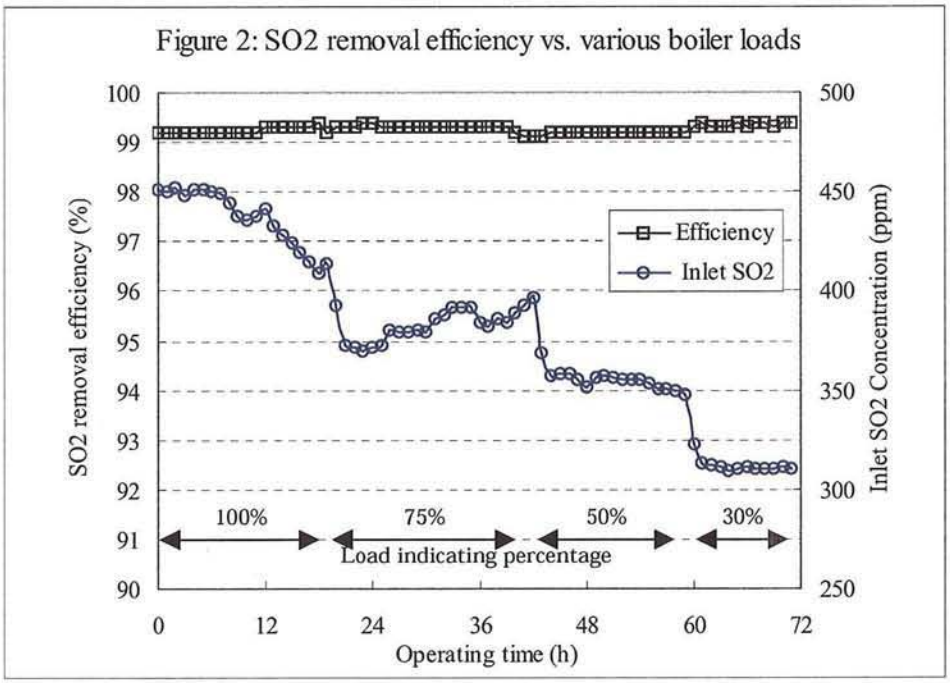
Table 2
Design Basis and Major Equipment of CT-121

Design Condition	
<Inlet>	
Flue Gas	Coal fired boiler flue gas
Gas Volume	1,395,000 scfm
SO_2 concentration	740 ppm (O2=6 % dry)
Particulate loading	0.0207 gr/scf (O2=6 % dry)
<Outlet>	
SO_2 removal efficiency	99 % (on an instantaneous basis)
Particulate loading	0.00236 gr/scf (O2=6 % dry)

Table 2 Design Basis and Major Equipment of CT-121	
Design Condition	
<Limestone>	
Purity	97 %
Particle Size	90 % passing through 200 mesh screen
<Gypsum>	
Purity	More than 95 %
Moisture Content	Less than 10 %
Major equipment of CT-121	
Absorber (JBR)	Rectangular type
	75.5 ft(W)×75.5 ft(L)×50.2 ft(H)
	No. of agitators : 4
Gas to Gas Heater	Non-leak type cyclic reheat GGH
Flue Gas Fan	Variable pitched axial blade fan
Gypsum Separator	Horizontal belt filter

The SO_2 removal efficiency of over 99 percent is the most stringent requirement for an IPP project with a coal-fired boiler in Japan. In addition, the CT-121 must meet other requirements as well, such as high particulate reduction and producing commercial grade gypsum.

Figure 2 shows the results of SO_2 removal performance at various boiler loads.



This figure shows superior SO_2 removal efficiency of over 99 percent on an instantaneous basis in the cases of varying load and inlet SO_2 concentration.

The CT-121 process is recognized as the pioneer of the limestone forced oxidation (LSFO) process. The CT-121 process uses a Jet Bubbling Reactor (JBR), which combines SO_2 absorption, forced oxidation reaction, neutralization reaction by limestone, and gypsum crystallization in one process vessel. Since these four reaction steps are performed simultaneously, the oxidation reaction of absorbed SO_2 proceeds very efficiently. Therefore, stable and higher SO_2 removal can be readily achieved due to a lack of any SO_2 backpressure in the JBR. This is the reason why the CT-121 can achieve high and stable SO_2 removal efficiency and maintain it under any circumstances.

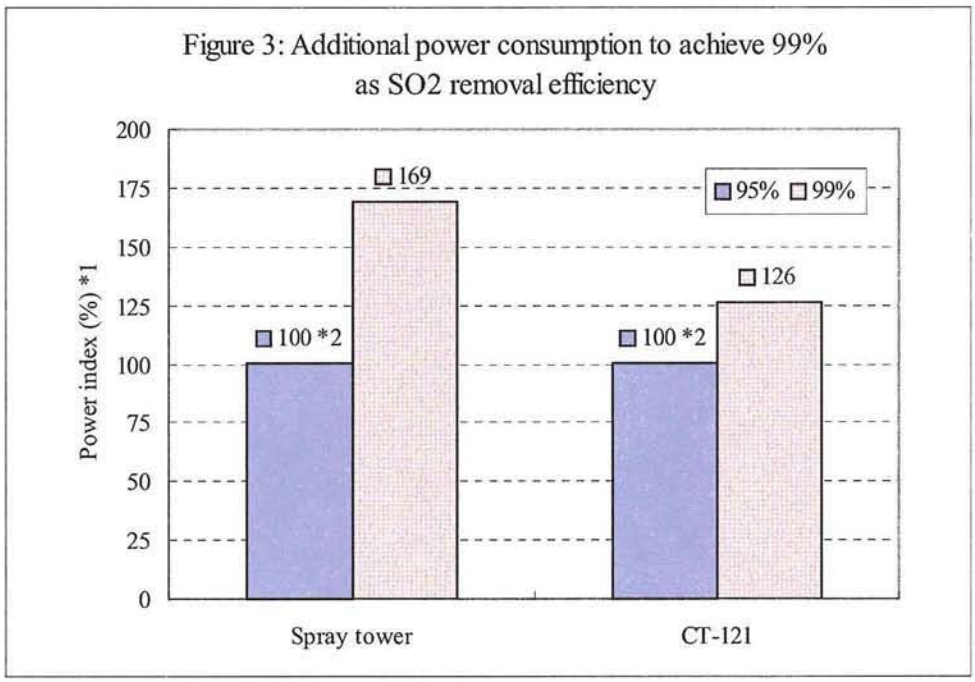
High SO_2 Removal Efficiency with Low Operating Cost

The CT-121 Kobe is designed for higher pH operation compared to the typical operating pH of other CT-121 installations. Achieving higher SO_2 removal efficiency by higher pH operation leads to the reduction of system pressure drop across the JBR, resulting in reduction of power consumption of flue gas fan.

The following sections describe the comparison between the CT-121 Kobe and spray tower processes regarding the additional power consumption required to achieve 99 percent SO_2 removal efficiency, as well as the cost reduction by the higher pH operation.

Additional power consumption to achieve 99percent from 95 percent

Figure 3 shows the additional power consumption to achieve 99 percent SO_2 removal efficiency compared with 95 percent SO_2 removal efficiency in the CT-121 and spray tower processes.



*1. Power consumption related to SO_2 removal efficiency (CT-121: Flue gas fan and gas cooling pumps, spray tower process: flue gas fan and recirculating pumps)

*2. Base 100 percent

This figure shows our calculation results of the spray tower's power consumption. The calculation base is "New Models for FGD Performance, Cost and Hazardous Sir Pollutant Removal" [1] published at the SO_2 Control Symposium in 1995.

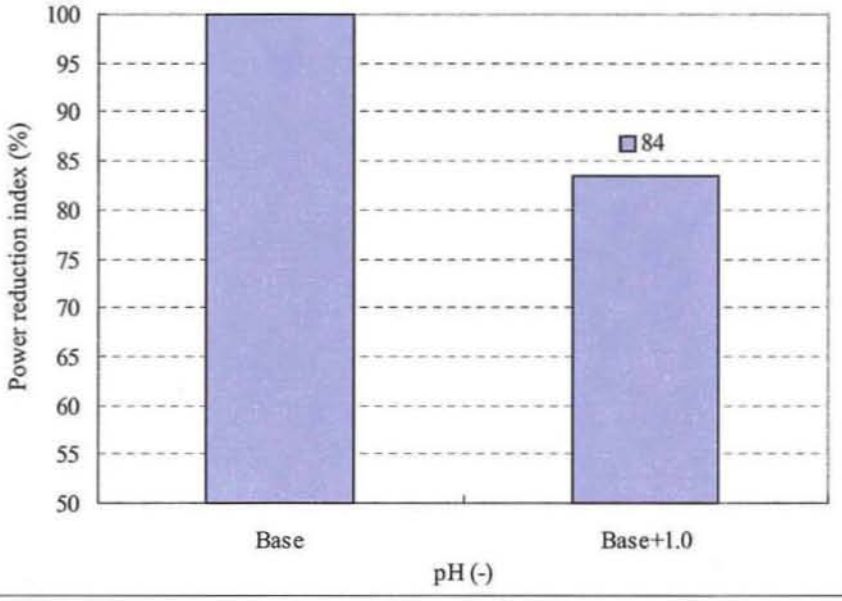
The figure illustrates that the CT-121 can achieve 99 percent SO_2 removal efficiency with only 26 percent additional power consumption. On the other hand, spray tower processes need almost 70 percent additional power consumption. This difference exists because the contact of gas to liquid by the jet bubbling mechanism is more efficient than spray tower processes.

Moreover, CT-121 Kobe could reduce its operating power consumption by the higher pH operation. The details are shown in the next section.

Power reduction by the higher pH operation

Power reduction in the CT-121 Kobe by higher pH operation is shown in Figure 4.

Figure 4: Power reduction by higher pH operation



In this Figure, the bar on the left shows the operating power in typical pH operation (Base) and the bar on the right shows the operating power in the higher pH operation (1.0 higher than the typical pH) in the CT-121 Kobe.

The CT-121 Kobe has successfully reduced the power consumption of flue gas fan by 16 percent through higher pH operation compared with the typical pH operation.

The operating pH of the CT-121 is usually lower than spray tower processes by approximately 1.0~1.5. Moreover, the pH of the jet bubbling layer where SO_2 is absorbed is lower than the pH at the pH measuring location. So in that layer, limestone can be dissolved easily.

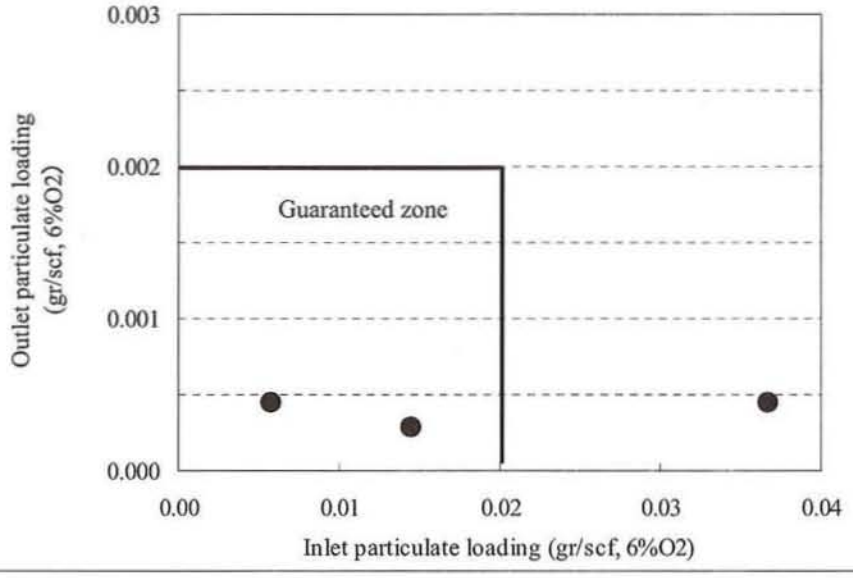
From our operating results of the CT-121 in existing installations, we have confirmed that limestone stoichiometry is only slightly increased even in the higher pH operation. That is why we applied the higher pH operation in the CT-121 Kobe. As expected, gypsum quality of higher than 95 percent has been maintained.

High Particulate Removal Efficiency

One of the most important features of the CT-121 is its high particulate removal efficiency, which is superior to spray tower processes.

Figure 5 shows the particulate removal performance of the CT-121 Kobe.

Figure 5: Particulate Loading at FGD inlet vs. Particulate Loading at FGD outlet



CT-121 Kobe can maintain stable high particulate removal efficiency at various inlet particulate loading rates (0～0.04 gr/scf).

This superior particulate removal efficiency is attributed to the efficient contact of gas to liquid by the jet bubbling mechanism. The particulate loading at FGD outlet is approximately 0.0005 gr/scf or less, compared with the guaranteed outlet particulate loading of 0.002 gr/scf.

REDUCTION OF CONSTRUCTION COST AND CONSTRUCTION WORK PERIOD

In addition to the high performance, the Kobe project emphasized cost reduction, including minimization of design cost, specification review of the main equipment, and examination of the installation method. The CT-121 has been improved continuously from the viewpoint of cost reduction based on the technologies developed by Chiyoda Corporation.

For example, cost reduction was realized by modifying the shape of the absorber as the gas throughput of the absorber was increased. The cylindrical structure was changed to a rectangular one, following the structure of the CT-121 for Haramachi Power Plant. Then, as a result of additional structural analysis, further progress was made in the design technique. In recent years, the rectangular-shape with combined-panel JBR, which is directly welded with the reinforcement pillars and beams, has become the standard for Chiyoda in Japan.

This chapter describes the results of our efforts in reducing the construction work period and reducing the construction cost for the JBR by making the best use of the advantages of the combined-panel JBR through effective utilization of heavy construction machines and cranes.

Reduction of Construction Work Period

The time required for the execution of the Kobe project was approximately three and one half years in total. This period includes design, manufacturing, construction, and commissioning. The duration of commissioning phase is not a process requirement, but contractual requirement. The scope of work includes not only desulfurization equipment (consisting of absorber, duct, mist eliminator, fan, belt filter, etc.), but also limestone storage equipment (including limestone powder silo and limestone powder receiving piping), the gypsum storage equipment (including gypsum silo, gypsum unloading machine, etc.) and the gypsum shipping equipment (including conveyor belt, ship loader, etc.). The gross weight of the equipment and apparatus used for this construction was approximately 4,000 tons. The items in the outline execution period were as follows.

Table 3
Project Execution Schedule

	Item	1998	1999	2000	2001	2002
1	Basic Design					
2	Detail Design					
3	Procurement					
4	Shop Fabrication					
5	Field Construction					
	JBR-Assembly					
	JBR-Flake lining					
	JBR-Internal work					
6	Commissioning					

Notes:
- The basic design was started when the kickoff meeting was held with the client.
- The foundation work is not included in the scope of work.
- The commissioning work includes BTG commissioning.

Table 4 shows the remarkable reduction ratio in the work period of the absorber assembly compared to the conventional construction of 700 MW FGD with rectangular JBR. The Table also shows the total manday reduction ratio in the field construction.

Table 4
Comparison of Work Period and Reduction of Construction Mandays in Absorber Construction

Construction Item	Kobe	Conventional construction method for 700 MW
Shell assembly period	70 %	100 %
Flake lining period	80 %	100 %
Internal work period	80 %	100 %
Total construction mandays	85 %	100 %

Note:
- The comparison is made based on actual construction cost data.

The reduction in the work period was achieved for each item and the labor reduction of 30 percent was achieved especially in the panel assembly steps where a new method of construction was adopted. This was achieved by the following factors:

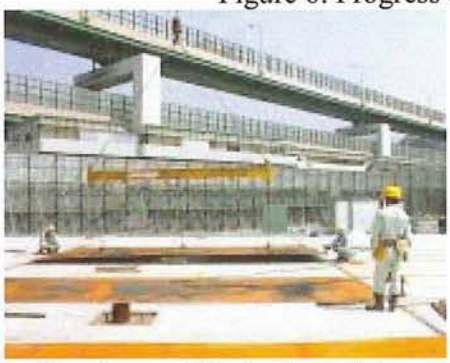
- Utilization of marine transportation and adoption of the large panel installation method.
- Increase in the prefabrication ratio.
- Securing the internal work environment by completing the roof panel installation in the early stage.

Since it was possible to unload items at a quay in the construction site, the side and roof panels of the absorber were manufactured in a factory and were divided into 15 large parts (for example, the size of one part was 28.9 ft × 74.5 ft × 3.9 ft, weighing 66,100 lb), thus increasing the prefabrication ratio considerably. Unloading of the parts was performed immediately before the side panel installation began without any loss of work period in the construction steps.

In the conventional method of construction, frame assembly and side panel installation was repeated step by step. It took about 75 days for the above-mentioned work. On the other hand, in large-sized panel construction, panel installation was completed for only three days. It took only 40 days for panel installation including internal beams after the panel installation was started. After the completion of panel installation, the roof panel was put into place. In addition, work delays due to bad weather could be avoided by closing the roof so quickly. This has also contributed to the reduction of construction work period.

Figure 6 shows the outline of absorber construction sequence of CT-121 Kobe.

Figure 6: Progress of Absorber Construction



Lay down of the bottom plates

Installation of the internal beam

Panel Installation
(2 days after the panel installation started)

Roof Panel Installation
(40 days after the panel installation started)

Overview of FGD Plant

The work period reduction was achieved compared with the past actual results in the flake lining and the internal works, which were performed after the shell assembly. The flake lining work is greatly dependent on the development of application technology. The spray

method, which is often used overseas, is also established in Japan. The method is expected to be more effective for larger equipment.

Additionally, the internal JBR decks are made of FRP. Considerable weight savings were achieved by use of FRP composite material of sandwiched structure. This savings contributed to the reduction of construction work volume. This FRP composite material has been used for airplanes and vessels for many years, especially in US and is also used in the aerospace field in recent years. It will continue to be used in a variety of fields as one of the state-of-the-art materials.

Reduction of Construction Cost

The following three key goals were set for achieving the reduction of construction cost:

- Material cost reduction.
- Shop fabrication cost reduction.
- Field construction cost reduction.

The comparison of construction cost based on the conventional method of a 700 MW absorber is shown below.

Table 5
Comparison of Construction Cost for Absorber Assembly

Item	Kobe	Conventional Rectangular Type
Steel weight	86 %	100 %
Shop fabrication cost	71 %	100 %
Field construction cost	71 %	100 %
Total assembly cost	67 %	100 %

Notes:
- The comparison is made based on actual construction cost data.
- The percentages are shown based on the conventional rectangular type as 100 percent.

Firstly, as has been previously described, the greatest factor of material cost reduction was the adoption of the combined shell structure. The design of the combined shell structure allowed us to replace the separated side panels with the brace of a frame. It enabled the weight reduction of steel materials because the quantity and size of a frame component were reduced from the conventional ones, and the main frame could be used both as a beam and as a stage structure without any modification.

Secondly, as adopting the new construction method for large-size panels increased the prefabrication ratio, it was expected that the ratio of shop fabrication cost would increase.

The overseas fabrication of the JBR was applied for the cost reduction of the shop fabrication cost due to the lower labor cost. However, risks such as quality deficiency from quick outsourcing were considered. Therefore, a subcontractor who carried out the design, fabrication and installation works in Japan for existing CT-121 installations and owns an overseas factory located in Indonesia, was selected. Cost reduction of 29 percent compared to the construction of the conventional rectangular type absorber could be achieved.

Thirdly, the cost reduction of the field construction is discussed hereinafter. The main factor, which contributed to the field construction cost reduction, was the reduction of work period. Another factor was the minimization of unnecessary unloading and secondary drayage by controlling on-site delivery of products using the just-in-time delivery system.

The cost reduction was achieved using all of the above-mentioned three key goals. The total reduction in the field construction cost reached 29 percent compared to the conventional rectangular type absorber.

Finally, we conclude this chapter emphasizing that we could achieve an overall cost reduction of 33 percent in the absorber construction including the flake lining and internal works compared to the conventional cylindrical type absorber, although our discussion was limited only to the absorber assembly in this paper.

RELEVANCE OF CT-121 KOBE EXPERIENCE TO NORTH AMERICAN APPLICATIONS

In North America, Chiyoda Corporation has entered into an exclusive licensing agreement with Black & Veatch Corporation for the CT-121 FGD process. As utility and industrial operators face increased requirements for environmental controls, it is expected that the high SO_2 removal capability and the low operating cost of the CT-121 as demonstrated at Shinko-Kobe Electric Power Plant will allow North American users to achieve their objectives for environmental compliance while maintaining competitive costs of generation.

US Environmental Regulations Will Tighten

Three bills were introduced to the 107th Congress proposing major reductions in air emissions from power generating facilities: Clear Skies Act of 2002, Clean Power Act and the Clean Air Planning Act. On February 12, 2003, Senator Jeffords re-introduced his Clean Power Act to Congress, and on February 27, 2003, President Bush's Clear Skies Act was re-introduced. These legislative proposals would transform the current air quality regulatory framework from a command-and-control approach to a market based cap-and-trade scheme. Not only would this effect a major overhaul in the regulation of sulfur dioxide, nitrogen oxide, mercury, and possibly carbon dioxide emissions, but some of these

legislative bills propose to transform or completely replace several major existing programs. Meanwhile, a significant and growing number of states have enacted their own, stringent air emission standards on one or more pollutants.

While these federal legislative proposals are intended to bring more conformity and certainty to the current situation, it is important to keep in mind that to date, these new programs are only proposals, and nothing has been passed to negate the current emissions regulations already in effect. The US Environmental Protection Agency is under court order to promulgate Maximum Achievable Control Technology (MACT) regulations for no less than 33 different source categories of hazardous air pollutant emissions in the coming year, as well as a mercury MACT standard for coal and oil fired boilers by December 2003. The NOx SIP call is set to begin in May 2004, which will be closely followed by designation of non-attainment areas under the new ozone and PM2.5 ambient air quality standards.

Under any new regulations requiring the installation of FGD equipment, cost of compliance will be a critical issue to be addressed. Moreover, under a cap-and-trade scheme as contemplated by Clear Skies and the Clean Power Act, the capability to achieve and maintain greater than 99 percent SO_2 removal, as demonstrated by CT-121 Kobe, can maximize the SO_2 reduction at every FGD installation and assist in reducing the overall cost of compliance.

It is anticipated that emissions reductions resulting from by the Regional Haze Rule and the PM2.5 National Ambient Air Quality Standard would include additional particulate control at some facilities. The superior particulate removal performance in the CT-121 could allow those facilities equipped with the CT-121 for SO_2 control to avoid modifications or upgrades to particulate control equipment.

Fuel Flexibility Enhances Compliance Options

CT-121 Kobe was designed for operation at 99 percent SO_2 removal for a one percent sulfur bituminous coal, analogous to an Eastern US low-sulfur coal. In the US, FGD installations have been completed for units firing much higher sulfur fuels, as high as 6 lb/MBtu or more. Nonetheless, process design modifications can accommodate high SO_2 removal requirements on a variety of fuels, and CT-121 has also been applied for high removal efficiency requirements on high sulfur applications. At Onahama Smelting and Refining Company, 99 percent SO_2 removal treating a gas stream from a sulfuric acid plant was guaranteed and achieved with an inlet concentration of 7,000 ppm SO_2. In addition, 15 other applications guaranteed and achieve greater than 95 percent SO_2 reduction with an inlet SO_2 concentration greater than 2,000 ppm. The fuel flexibility afforded by CT-121 may allow the FGD installation to enhance an overall fuels strategy.

As discussed previously, the efficiency of gas-liquid contact in the CT-121 allows the process to accommodate increased removal efficiency at a lower incremental power

consumption compared to conventional spray towers. As a corollary benefit, CT-121 can achieve and maintain high and stable SO_2 removal under varying SO_2 inlet conditions. This results in a reduced operating margin being required to maintain compliance, allowing greater variations in coal quality while maintaining environmental compliance.

Reducing Construction Cost Risk

Construction costs remain the single greatest risk contributor to cost overruns on FGD installation projects. Construction costs can escalate tremendously when the available construction labor resources are exceeded. If environmental retrofit projects proceed as expected, whether under Clear Skies, mercury MACT, or other programs, construction labor resources could be constrained. In the US as in Japan, maximum shop fabrication and assembly is the primary execution strategy to deal with site challenges and project resource limitations.

Shop labor, combined with shop productivity rates and specialized equipment, produce work for 35 to 50 percent of the cost for the same activities performed in the field. Additional costs are incurred for shipping and erection of large components, but the net savings usually favors maximum shop fabrication. Many US fabricators have their shops in the Gulf Coast region where barge access permits greater weights (up to 200 tons) and greater physical dimensions than permitted for truckable modules (limited to 50 tons in most locations).

In addition to the overall schedule savings afforded by panel construction of the JBR, this method can allow construction of the absorber module to be taken off the critical path. In doing so, the required labor resources can be levelized against construction of the new chimney (if required) or the limestone preparation system. Panel construction of the JBR can reduce project costs by maximizing shop fabrication, reducing the overall schedule, and levelizing labor requirements.

CONCLUSIONS

This paper describes our commercial experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant. The operating and construction experiences are summarized as follows:

- The CT-121 can maintain stable SO_2 removal efficiency of over 99 percent on an instantaneous basis.
- Higher pH operation allowed 99 percent SO_2 removal efficiency with only slight additional power consumption.
- The particulate removal efficiency is superior to that of other spray tower processes.

- Applying the panel construction method results in the reduction of construction cost and reduction of work period.

Application of the CT-121 capabilities and construction cost reduction methods in North America as demonstrated at Shinko-Kobe Electric Power Plant will allow North American users to achieve their objectives for environmental compliance while maintaining competitive costs of generation by:

- Accommodating a wide variety of fuels and inlet conditions.
- Maximizing the results of an investment in FGD technology.
- Avoiding costly particulate control modifications or upgrades.
- Reducing project costs and cost variance through panel construction of the JBR.

ACKNOWLEDGEMENTS

The authors acknowledge the cooperation of Shinko-Kobe Electric Power Plant and Kobe Steel from the early design stage of CT-121 FGD throughout the construction and commissioning.

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KEYWORDS

Black & Veatch
Chiyoda
Construction
CT-121
Flue Gas Desulfurization (FGD)
Kobe
Particulate

Flue Gas Desulphurization

Reference list CT-121

Owner	Country	Fuel	MWe	Year	Eff. %	By-product Gypsum
Georgia Power Co.,	U.S.A.	Coal	2x750	2010	98	Wallboard
Alabama Power Co.,	U.S.A.	Coal	340	2009	98	Cement
American Electric Power Co.,	U.S.A.	Coal	865	2009	98	Throwaway
American Electric Power Co.,	U.S.A.	Coal	850	2009	98	Throwaway
Alabama Power Co.,	U.S.A.	Coal	950	2009	98	Wallboard
Georgia Power Co.,	U.S.A.	Coal	950	2009	98	Wallboard
Dayton Power & Light Co.,	U.S.A.	Coal	2x620	2009	97	Wallboard, Cement
American Electric Power Co.,	U.S.A.	Coal	2x618	2008	98	Landfill
American Electric Power Co.,	U.S.A.	Coal	675	2008	98	Throwaway
American Electric Power Co.,	U.S.A.	Coal	450	2008	98	Throwaway
American Electric Power Co.,	U.S.A.	Coal	640	2008	98	Throwaway
American Electric Power Co.,	U.S.A.	Coal	2x620	2008	98	Wallboard/cement
Georgia Power Co.,	U.S.A.	Coal	3x950	2008	98	Wallboard
Dayton Power & Light Co.,	U.S.A.	Coal	2x620	2008	97	Wallboard/cement
Shanxi Hexin Electricity Co., Ltd.	China	Coal	2x600	2008	95	Wallboard/cement
Guohua Electric Power	China	Coal	4x600	2007	95	
Dayton Power & Light Co.,	U.S.A.	Coal	660	2007	97	Wallboard/cement
Taishan Power Co., Ltd.	China	Coal	3x600	2007	95	Wallboard/cement
Huaneng Electric Power Co., Ltd.	China	Coal	2x330	2005	95	Wallboard/cement
Taishan Power Co., Ltd.	China	Coal	2x600	2005	95	Wallboard/cement
Kansai Electric Power Co., Inc.	Japan	Coal	900	2004	94	Wallboard/cement
Kobe Steel Ltd.	Japan	Coal	2x700	2002	99	Cement
Okinawa Electric Power Co.	Japan	Coal	220	2002	82	Cement
Dong Energy A/S	Denmark	Coal	250	2000	98	Wallboard/cement
Kuwait National Petroleum Co.	Kuwait	Petcoke	80*	1999	95	Wallboard/cement
Kashima-Kita Electric Power Co.	Japan	Oil/Orimulsion	149*	1999	98	Wallboard
Korea Electric Power Corporation	Korea	Oil	3x400	1999	90	Wallboard/cement
Tokuyama Corporation	Japan	Coal	190*	1998	99	Cement
Tohoku Electric Power Co., Inc.	Japan	Coal	1.000	1998	92	Wallboard/cement
Hokuriku Electric Power Co.	Japan	Coal	700	1998	94	Wallboard/cement
Asahi Kasei Corporation	Japan	Asphalt	100*	1998	98	Wallboard/cement
CEZ a.s.	Czech Republic	Lignite	4x200	1997	96	Ash stabilizer
Suncor Inc.	Canada	Petcoke	350	1996	95	Deposit
Okinawa Electric Power Co.	Japan	Coal	156	1995	85	Wallboard/cement
Hokuriku Electric Power Co.	Japan	Coal	500	1995	91	Cement
Okinawa Electric Power Co.	Japan	Coal	156	1994	85	Cement
Chubu Electric Power Co., Inc.	Japan	Coal	2 x 350	1993	94	Cement
Tokuyama Corporation	Japan	Oil	78	1993	95	Wallboard/cement
Georgia Power Co.	U.S.A.	Coal	110	1992	95	Fertilizer
Hokuriku Electric Power Co.	Japan	Oil	350	1990	93	Wallboard
Wieland Werke AG	Germany	Coal	12	1989	90	Wallboard/cement
State of Illinois	U.S.A.	Coal	40*	1988	94	Wallboard
Hokuriku Electric Power Co.	Japan	Oil	250	1987	95	Wallboard/cement
Kashima-Kita Electric Power Co.	Japan	Oil/Orimulsion	225	1985	97	Wallboard/cement
Toyama Kyodo Electric Power Co.	Japan	Coal	2x250	1984	90	Wallboard/cement
Nippon Mining Co., Ltd.	Japan	Oil	75	1983	95	Wallboard/cement
Mitsubishi Petrochemical Co., Ltd.	Japan	Oil	85	1982	97	Wallboard/cement
Gulf Power Co.	U.S.A.	Coal	23	1978	95	Fertilizer

*MWe-equivalent

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High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market

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Abstract

Recent awards in the U.S. have highlighted the advantages of the MHI "double contact flow scrubber" or DCFS FGD system which has been applied to large-scale units during the latter years of the 1990's. This paper provides a detailed description of the DCFS FGD system including operating data from recent installations.

The DCFS design features are discussed in detail including the single header stage fountain spray design, including the single and twin tower design. The operating experience of recent installations is reviewed including case studies for selected systems.

Recent operating experience is reviewed in detail. In particular, the paper highlights design requirements to achieve SO_2 removal efficiencies as high as 99.9 percent on high sulfur coals without the use of buffer additives, particular removal efficiencies as high as 90 percent, while producing wallboard grade gypsum and maintaining 100 percent system availability in operation for the duration of over 2 to 4 years.

The DCFS design allows utilities to use a high degree of standardized equipment on a single installation. Modularization of the DCFS design extends the standardization features to multiple plants regardless of differences in absorber size. The standardization and modularization features of the DFCS design are discussed in detail.

The Paradise DCFS system currently in the engineering phase is discussed in detail.

Background

MHI is the world's leading supplier of FGD systems, with over 60,000 MWe installed on 154 boilers in 14 countries. The first MHI FGD system was installed in 1964. MHI's wet FGD system has evolved to a very simple, reliable and highly efficient single loop, Double Contact Flow Scrubber. During recent years, prominent technology improvements have included the single stage DCFS spray header design, air rotary sparger for combined slurry mixing and gypsum oxidation, and jet air sparger for gypsum oxidation without use of oxidation compressors. This paper presents an overview of the MHI Double Contact Flow Scrubber, recent operating experience, and provides an overview of the scrubber design for the TVA Paradise FGD system currently in the engineering phase.

DCFS Features

The double contact flow scrubber comes in two design configurations; single tower and twin tower as shown in Figure 1. The single tower design is typically used on low-to-medium sulfur coals and SO_2 removal efficiencies up to 97 percent. The twin tower design is typically used on medium-to-high sulfur coals and SO_2 removal efficiencies above 97 percent or to achieve very high particulate removal efficiencies. This paper will mainly focus on the twin tower design.

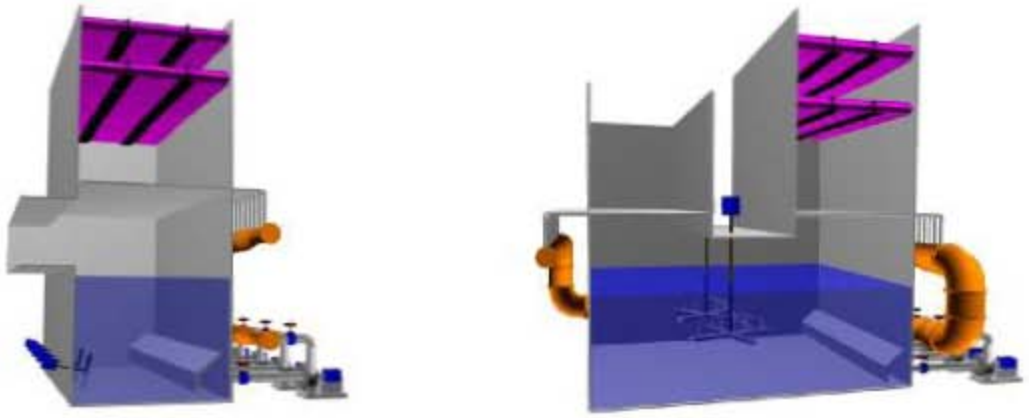

Figure 1. Single and Twin Tower DCFS system

Twin Tower DCFS

As the flue gas enters the top of the first tower, the wet dry interface is located nearly 8 feet into the top part of the vessel. This interface is washed routinely with fresh make-up water to minimize build-up of fly ash entrained in the flue gas. The flue gas encounters the top of the fountain spray as the gas flows counter-current to the spray in the first of the twin towers. The recycle slurry is spouted upwards in fountain-like spray by multiple single-stage nozzles installed on a single spray header located at the lower section of the first and second towers. This fountain or liquid column in the DCFS contacts the flue gas as it proceeds counter-current to the liquid spray and again co-current as liquid and gas flow downward together. This "Double Contact" provides for intimate contact for

absorption of SO_2, excellent utilization of the limestone reagent, and a very high level of removal of incoming fly ash.

As the gas leaves the first tower, it traverses the top of slurry in the reaction tank before entering the second tower. In the second tower, the flue gas passes co-current to the flow of the fountain spray and counter-current to falling droplets of slurry. This additional second tower and "double contact" design provides the additional gas-liquid contact such that the resulting SO_2 removal efficiency can be as high as 99.9%. The gas velocity in the first tower is typically between 15 to 30 fps while the velocity in the second tower is typically between 14 to 20 fps. This makes the absorber tower very compact and cost effective.

The absorber tower is equipped with a single-level spray header in each tower. Low-pressure silicon carbide nozzles are used to provide a fountain-like spray reaching about 15 ft to 30 ft in height. The recycle slurry exits the spray nozzle much like a liquid rod that gradually disintegrates into very large spray droplets as the slurry decelerates and is pulled back into the recycle tank by gravity. The fountain-type spray header design provides a very high degree of gas-to-liquid contact and a high degree of surface renewal that improves the recycle slurry's neutralization capacity. The flue gas also contacts the slurry twice as the liquid exits the nozzles and ultimately returns to the reaction tank. A picture of the fountain spray is shown in Figure 2.

Figure 2. MHI full-scale spray header test rig

The spray headers are connected to a single recycle header pipe that in turn is connected to the recycle pumps. The spray nozzle has no internals, provide maximum free passage, and a very low pressure drop as it is essentially an open pipe. The nozzle is made from a ceramic material and, because of the low pressure drop, experiences essentially no wear over the life of the FGD system. The MHI spray nozzle is shown in Figure 3. The spray from the spray nozzle is introduced parallel to the absorber walls and hence, wall erosion or header to header erosion is not a problem with this design. Also, as the spray is directed away from the inlet duct, no buildup in the inlet duct is experienced.

Figure 3. MHI low pressure drop, maximum free passage spray nozzle

A pump suction deflection/screening plate is located in close proximity to the pump suction and spans the entire side of the reaction tank. The screening plate is installed to

prevent air that is sparged into the reaction tank from being entrained into the recycle pumps and recycle piping. Each pump is connected to a common recycle header and is isolated on the suction and discharge sides of the pump with knife-gate or butterfly valves. Each pump, gear box, and motor is identical providing a high degree of standardization. The first series of pumps are connected to a common manifold which feeds the single spray header in the 2nd tower. The last series of pumps are connected to a common manifold that feeds the 1st tower. A spare pump is available to connect to the 1st or 2nd recycle header. A typical arrangement of the recycle pump bay is shown in Figure 4.

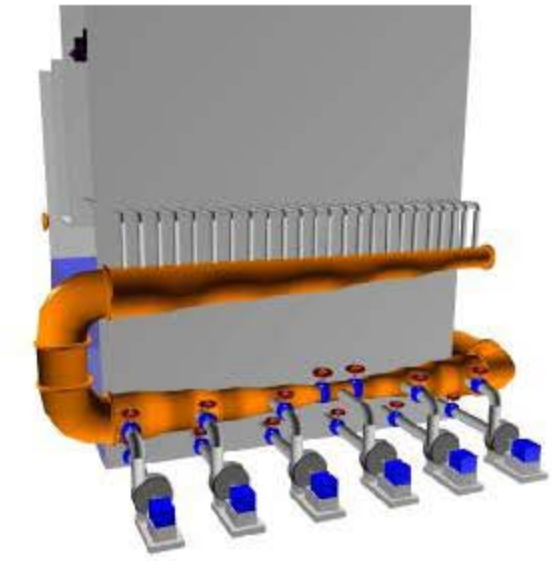

Figure 4. The DCFS recycle pump bay

The reaction tank operates at 30 percent solids which promotes gypsum crystal growth and significantly reduces gypsum scaling. Also, the high level of suspended solids in the reaction tank provides elevated levels of limestone which promotes SO_2 removal and makes the system more tolerant to swings in inlet SO_2 concentration.

The twin tower design has the added advantage of using top-mounted agitators, which also double as air spargers. This proprietary design, called the Air Rotary Sparger or "ARS," is highly efficient in terms of mixing and oxidation . The ARS oxidation and agitation system is shown in Figure 5.

In addition to superior agitation, top-mounted agitators are inherently leak free as the penetration through the absorber shell is above the slurry level in the reaction tank. The ARS is also used to distribute the oxidation air. Compressed air is distributed to the horizontal arms of the agitator and sparged into the recycle slurry. This approach is highly efficient and requires a lower quantity of air compared to side entry agitators or a fixed grid sparger system. Hence, the power spent on agitation is more than offset by the reduction in power consumed by the oxidation air blowers.

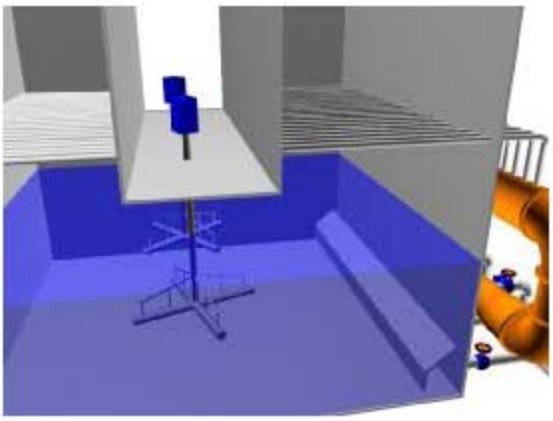

Figure 5. Air rotary sparger for agitation and forced oxidation

After the flue gas exits the spray zone of the second tower, it passes through a two-stage vertical flow mist eliminator. A 9 ft slurry and gas disengagement zone is provided between the top of the spray zone and the face of the first-stage mist eliminator. The provided disengagement zone, coupled with the very large droplets produced by the fountain-type spray headers, results in a very low liquid loading to the mist eliminator, even at elevated gas velocities.

As the DCFS FGD system operates at 30 percent suspended solids, the system does not require a primary dewatering system. The absorber bleed pumps can feed directly to a belt-filter or drum filter for dewatering to desired moisture level. This efficient design eliminates the primary dewatering step reducing the cost and complexity of the overall system.

Single Tower DCFS

The single tower DCFS system is very similar to twin tower with a few exceptions. First, this tower design is typically applied on low to medium sulfur coals and for SO_2 removal efficiencies at or below 97 percent. In the single tower design, the flue gas enters the absorber module from the side through a traditional absorber inlet design and exits the absorber at the top of the module as shown in Figure 1. A single fountain type spray header is located immediately above the inlet duct. No buildup in the inlet duct is experienced as the fountain spray is directed away from the inlet duct and parallel to the absorber walls. The Recycle slurry pumps configuration is identical to the twin tower design.

Agitation is achieved with either side entry agitators or by using the jet air sparger system. The single tower design has a fixed front to back distance of about 30 ft which makes side entry agitators very effective. An alternative to side entry agitators is the Jet Air Sparger (JAS) system which use a small portion of the recycle slurry flow to inject oxidation air through a eductor configuration. The eductors are located at the same place side entry agitators would be located. Hence, the JAS system can provide efficient oxidation and agitation without the use of agitators and the need of oxidation compressors. JAS systems operate successfully at several installations.

Standardization and Modularization

The MHI DCFS FGD system is specifically designed to simplify design, engineering, and construction, and to maximize the portion of the system that can be prefabricated and brought to the site in large pieces:

- The absorber walls are comprised of standardized panels that are joined together.
- The front-to-back distance is constant for absorber sizes larger than 200 MWe up to an absorber size as large as 1,200 MWe.
- All recycle pumps systems are identical, including flow rate, discharge pressure, gear boxes, and electrical motor.
- All recycle pump isolation valves are identical.
- All top mounted (ARS) or side-mounted agitators are identical.
- All spray headers and spray nozzles are identical.

The design of the MHI DCFS system is highly standardized, and the size of the absorber tower only expands in one direction to accommodate different volumes of flue gas, as shown in Figure 6. Therefore, the DCFS design, in addition to standardization, lends

itself to adopting a modular design approach. This approach is ideal for system-wide application when multiple size boilers are involved.

By using a modular approach and multiple absorber sizes in steps of 200 MWe, the cost of the FGD retrofit project can be reduced substantially. All FGD module sizes considered would be identical except for the width of the absorber module. The depth and the height will be the same; the pump size, header size, nozzle size, agitator size, and air compressor size will all be the same – making it possible for plants to share spare parts or have a common spare parts facility. Finally, in the MHI FGD design, all recycle pumps, gearboxes, and motors are identical since the DCFS design only uses one spray header at one elevation, exposing all recycle pumps to the same pump head pressure.

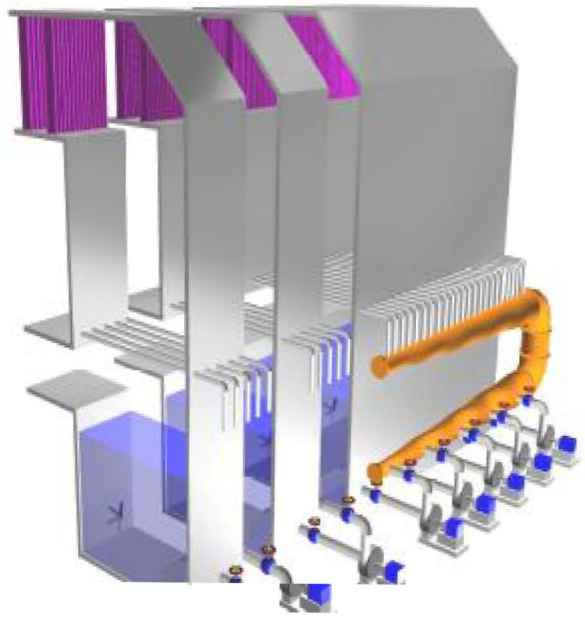

Figure 6. DCFS modularization Approach

For a typical system wide applications of the DCFS system, a base absorber of e.g. 300 MWe in size is selected and add-on modules of 200 MWe in size used to provide module sizes of 500, 700, 900, and 1100 MWe. As shown in Table 1, the DCFS system can provide a very high degree of standardization on multiple absorber sizes including these different sized modules will use the same size, model, and type of equipment, including recycle pumps, gear boxes, motors, agitators, blowers, spray headers, spray nozzles and mist eliminator, etc.

Table 1 Standardization and Modularization capability of the DCFS system

Equipment	Single Unit, One Size 500 MW		Multiple Units, Multiple Sizes 300, 500, 700, 900 1,100 MW	
	Spray/Tray Tower	DCFS System	Spray/Tray Tower	DCFS System
Recycle Pumps	Same	Same	Different	Same
Recycle Pumps Gear Boxes	Different	Same	Different	Same
Recycle Pump Motors	Different	Same	Different	Same
Recycle Pump Isolation Valves	Same	Same	Different	Same
Agitators	Same	Same	Different	Same
Agitator Motors	Same	Same	Different	Same
Recycle Headers	Same	Same	Different	Same
Recycle Nozzles	Same	Same	Different	Same
Mist Eliminator	Same	Same	Same	Same
Mist Eliminator Wash Nozzles	Same	Same	Different	Same

The modularization approach makes it possible to benefit from standardized equipment across a fleet of FGD system basically independent of absorber size. Hence, a shared or a common spare parts inventory is feasible. It is also feasible to minimize the number of absorber modules required can be reduced by treating two boilers with one absorber module. For example, a 178 MW and a 348 MW module can be treated in one 600 MW absorber module as is currently done at the Bailly Station in Indiana.

Development History of DCFS

After completion of fundamental tests using 15,000 m^3N/h pilot facility at MHI Hiroshima R&D Center, the DCFS was subjected to joint Verification tests with Chubu Electric Power Co. and Chugoku Electric Power Co. using actual coal flue gas in 15,000 m^3N/h and 300,000 m^3N/h facilities respectively. Subsequently, counter-current DCFS was selected for the 136 MW heavy oil-fired No. 2 unit of Kashima-minami Joint power station in 1993 followed by a co-current DCFS system for coal-fired 175 MW No. 1 unit of Chugoku Electric's Shimonoseki power station in 1994. A large scale co-current DCFS system was installed in 1998 at the 1,000MW Misumi Power station of Chugoku Electric Power Co., followed by a 2000 1,050 MW twin tower DCFS system at the EPDC Tachibanawan station and a 700MW twin tower DCFS system at Shikoku Electric Power Co. Tachibanawan A high performance twin tower DCFS system was installed in 1998 at the 149 MW KOA oil refinery in Osaka. This system provides a SO_2 removal efficiency of 99.9 percent on high sulfur fuel oil. More than 20,000 MW of DCFS systems have been sold and/or installed since the introduction of the DCFS system in 1993.

Experience

MHI has experience with a wide range of operating conditions as shown in Table 2. It is noteworthy that MHI has never installed a spare operating module at any of its 155 installations. However, most of the MHI systems operate a very high availability levels. The experience on high sulfur coals is very extensive with the highest SO_2 concentration experienced at 7,800 ppm. The experience with large single modules and high SO_2 removal efficiencies is also extensive.

Table 2. Overview of MHI FGD Experience

Installed FGD Capacity	~60,000 MWe
FGD Orders Last 10 Years	~30,000 MWe
Highest SO_2 Guaranteed Removal	99.80%
Highest SO_2 Removal w/o Additives	99.90%
Highest SO_2 Concentration	7,800 ppm
Largest Single Absorber	1,050 MWe
Longest Time between Outages	4 yrs
Spare Modules Installed	None
Highest Availability, Single Module	100% / 9yrs

Large Single Modules

MHI has experience with the single absorber modules starting at a moderate size of 150 MWe to the largest absorbers in the world at 1,050 MWe. The vast majority of our FGD systems are based on a single absorber module, regardless of size. All systems operate without installed spare module capacity.

The experience with different size absorbers is less of an issue with the MHI design. The depth and height of the MHI absorber are basically independent of absorber size. To accommodate a larger flue gas volume, the absorber tower is made wider, keeping all critical dimensions impacting gas/liquid contact unchanged from project to project The experience with large single modules is shown in Table 3.

Table 3. Experience with Large Absorber Modules

Customer (Location)	Capacity (MW)	SO_2 Content		Removal (%)
		Inlet (ppm)	Outlet (ppm)	
Electric Power Development Co.,Ltd. (Tachibanawan,Japan)	1,050×1	882	44	95.0
Tohoku Electric Power Co., Inc. (Haramachi#1,Japan)	1,000×1	910	70	92.3
Sohma Joint Thermal Power, Ltd. (Sohma, Japan)	1000×1	1,015	102	90.0
Chugoku Electric Power Co., Inc.(Misumi,Japan)	1,000×1	921	91	90.2
Kansai Electric Power Co., Inc. (Matsuura, Japan)	700×1	1,015	91	91.0
Chubu Electric Power Co., Inc. (Hekinan, Japan)	700×1	803	51	93.6
Chubu Electric Power Co., Inc. (Hekinan, Japan)	700×1	803	51	93.6
Chubu Electric Power Co., Inc. (Hekinan, Japan)	700×1	803	51	93.6
Electricity Generating Authority of Thailand (Ratchaburi, Thailand)	700×1	1,733	79	95.4
Electricity Generating Authority of Thailand (Ratchaburi, Thailand)	700×1	1,733	79	95.4
Shikoku Electric Power Co.,Ltd.(Tachibanawan, Japan)	700×1	840	46	94.5
ENEL (Brindisi Sud, #4, Italy)	660×1	1,610	81	95.0
ENEL (Brindisi Sud, #3, Italy)	660×1	1,610	81	95.0

High SO_2 Removal Efficiency

The fountain spray design generates very effective gas/liquid contact, and the DCFS FGD design is capable of very high SO_2 removal efficiencies. The DCFS system has proven performance on all ranges of sulfur and very high SO_2 removal performance up to 99.9%. Table 4 provides a partial listing of FGD plants operating at an SO_2 removal efficiency of 98% or higher.

The highest SO_2 removal guaranteed by MHI was 99.8% on a sulfur loading of 2,200 ppm SO_2. During guarantee testing, this unit recorded an SO_2 removal efficiency of 99.9% or 2 ppm SO_2 in the outlet duct. MHI has 50 FGD plants operating at an SO_2 removal efficiency of 95% or higher, 25 plants above 96%, 12 plants above 97%, 10 plants above 98%, and 4 plants above 99%.

Table 4. Experience with High SO_2 Removal Efficiencies

Year	Customer (Location)	Capacity (MW)	SO_2 Content		Removal (%)
			Inlet (ppm)	Outlet (ppm)	
1998	KOA Oil Co., Ltd. (Osaka, Japan)	149×1	2,219	4	99.8
2003	COSMO OIL Co., Ltd. (Yokkaichi, Japan)	223x1	3,433	17	99.5
2004	KOA OIL Co., Ltd. (Marifu, Japan)	149x1	4,087	25	99.4
1997	ENEL (Sulcis, #3, Italy)	240×1	5,740	81	98.6
1994	ENEL (Sulcis, #2, Italy)	240×1	5,740	81	98.6
1993	ENEL (Sulcis, #1, Italy)	240×1	5,740	81	98.6
2004	Nippon Mitsubishi Petroleum Refining Co., Ltd. (Muroran, Japan)	99x1	2,917	50	98.3
2003	Kashima Northern Electric Power Co. (Kashima-Kita #3, Japan)	300x1/2	5,886	117	98.0
2002	Kansai Electric Power Co., Inc. (Gobo #3, Japan)	600x1	554	16	97.0
1975	Teijin, Ltd. (Ehime, Japan)	-	1,740	53	97.0
1977	Chugoku Electric Power Co., Inc. (Shimonoseki, Japan)	400×1	1,645	53	96.8
1964	NKK Corp. (Koyasu)	-	3,070	102	96.7

High System Availability

Historically, the fundamental shortcoming of FGD systems has been their availability and the resulting impact on power generation. This shortcoming was particularly evident in the late '70s and early '80s. The Clean Air Act Phase I FGD systems had addressed most of the earlier problems and improved the availability records to be in the high 90s. However, most Phase 1 FGD systems included a spare absorber module.

Table 5. Availability of single module DCFS Systems

Year	Customer (Location)	Capacity (MW)	Gas Source	Removal (%)	Operating Time (years)	Achieved Cumulative Availability (%)
2002	Kansai Electric Power Co., Inc. (Gobo #3, Japan)	600x1	Oil-Fired	97.0	1-2	100
2002	Hokkaido Electric Power Co.,Inc. (Tomatoh-atsuma #4, Japan)	700x1	Coal-Fired	94.8	2	100
1977	Chugoku Electric Power Co., Inc. (Shimonoseki, Japan)	400×1	Oil-Fired Boiler	96.8	2	100
2000	Nakayama Nagoya Joint Thermal (Nagoya, Japan)	149×1	Coal-Fired Boiler	95.0	1	100
2000	Shikoku Electric Power Co.,Ltd.(Tachibanawan, Japan)	700×1	Coal-Fired	94.5	2	100
2000	Electric Power Development Co.,Ltd. (Tachibanawan,Japan)	1,050×1	Coal-Fired	95.0	2	100
1999	Electricity Generating Authority of Thailand (Ratchaburi, Thailand)	700×1	Oil-Fired	95.4	2	100
1998	KOA Oil Co., Ltd. (Osaka, Japan)	149×1	VR Fired Boiler	99.8	1-4	100
1998	Chugoku Electric Power Co., Inc.(Misumi,Japan)	1,000×1	Coal-Fired	90.2	2	100
1997	Sumitomo Osaka Cement Co.,Ltd.(Ako,Japan)	100×1	Coal-Fired	96.3	1	99.9
1997	Fukui Joint Thermal Power Co., Ltd. (Mikuni, Japan)	250×1	Oil-Fired Boiler	95.0	2	100
1976	Kashima South Joint Power Corporation (Kashima, Japan)	146×1	Oil-Fired Boiler	94.0	1	100

The drive in the domestic Japanese market has been to higher and higher availability, up to and including 100% online time. The DCFS technology was successfully developed to meet the market need for ultra high availability using a single absorber module. Table 5 shows the DCFS availability record of selected DCFS installations. The availability data shown on Table 5 are the cumulative availability over the operational period (life of system) thus far. The simplicity of the DCFS design, combined with extensive experience and lessons learned, makes it possible to design the DCFS system to achieve 100% availability with a single absorber.

Case Studies

EPDC – 1,050 MW Single Module DCFS System

The FGD system at EPDC's Tachibanawan station is the largest capacity absorber in the world, treating the entire flue gas volume of the 1,050 MW boiler in a single module. The absorber is the twin-tower Double Contact Flow Scrubber (DCFS) type including a co-current flow tower and a counter-current flow tower. The absorber was designed to comply with extremely stringent particulate and SO_2 regulations. Particulate emissions are regularly below 5mg/Nm^3 and SO_2 removal efficiency above 95 percent. The FGD process control system is designed to automatically control the number of pumps in service depending on boiler load and coal sulfur levels. Since the inlet

Figure 7. EPDC Tachibanawan 1,050 MW Single module DCFS system

SO_2 concentration is lower than the designed value, the absorber is automatically being operated with a reduced number of slurry recirculation pumps, resulting in reduced power consumption. Th system produce wallboard grade gypsum which is sold locally. The FGD plant has been in commercial operation for two years and has achieved cumulative availability of 100 percent.

KOA – 99.9% SO_2 Removal

The FGD plant at the KOA refinery is a high sulfur twin tower DCFS application that has achieved the industry's highest desulfurization performance of 99.9% exceeding the guaranteed SO_2 removal efficiency of 99.8 percent without using performance additives. The FGD system has the equivalent size of 149 MWe and treats flue gas from a vacuum residue boiler. The SO_2 concentration ahead of the FGD system is typically about 2,000 ppm while the SO_2 concentration in the stack is below 2 ppm. In addition to emitting very low SO_2 emissions, particulate emissions are typically below 1.3 mg/Nm^3. In the past, such a high desulfurization capability has been considered impossible without the use of additives. It is achievable with the twin tower DCFS design, due to the excellent gas/liquid contact and the absence of gas sneakage along the absorber walls. The unit went into operation in 1998 and has achieved a cumulative availability of 100 percent since startup.

Figure 8. KOA high efficiency DCFS system

North American Activities

MHI in partnership with URS through a Joint Venture company named Advatech is marketing MHI's DCFS FGD system in North America. Advatech is currently providing design and implementation services for the Tennessee Valley Authority for up to five FGD systems. The first FGD system will be installed at the Paradise station on the Unit 3 boiler. This system will be put in operation in 2005 to 2006 time frame. Also, a conversion of the Widows Creek Unit 8 FGD system to a twin tower DCFS design is currently underway. The Widows Creek DCFS system will be operational in December of 2003. A more detailed description of the Paradise project is provided below.

Paradise Unit 3 FGD System

Advatech has been awarded the FGD system for the Paradise Unit 3 station which is a 1,050 MWe pulverized coal-fired boiloer firing high sulfur eastern bituminous coal. Advatech will provide EPC services for the entire scope including limestone preparation, absorber island, fans, ductwork, stack and balance of plant.

The FGD system will based on the MHI DCFS twin tower design and will utilize a single absorber tower which will provide a SO_2 removal efficiency of 98 percent. A pictorial of the FGD system layout is shown in Figure 9. The FGD inlet is symmetrically divided to take flue gas from each of the ESP trains. New booster fans are provided and are close coupled with each of the absorber inlet ducts

The flue gas encounters the top of the fountain spray as the gas flows counter-current to the spray in the first of the twin towers. The recycle slurry is spouted upwards in fountain-like spray by multiple single-stage nozzles installed on a single spray header located at the lower section of the first and second towers. The nature of this design makes it impossible to get recycle slurry into the absorber inlet ductwork or booster fans, which has been a common problem with spray and tray towers in recent years. This fountain or liquid column in the DCFS contacts the flue gas as it proceeds counter-current to the liquid spray and again co-current as liquid and gas flow downward together. This "Double Contact" provides for intimate contact for absorption of SO_2, excellent utilization of the limestone reagent, and a very high level of removal of incoming fly ash.

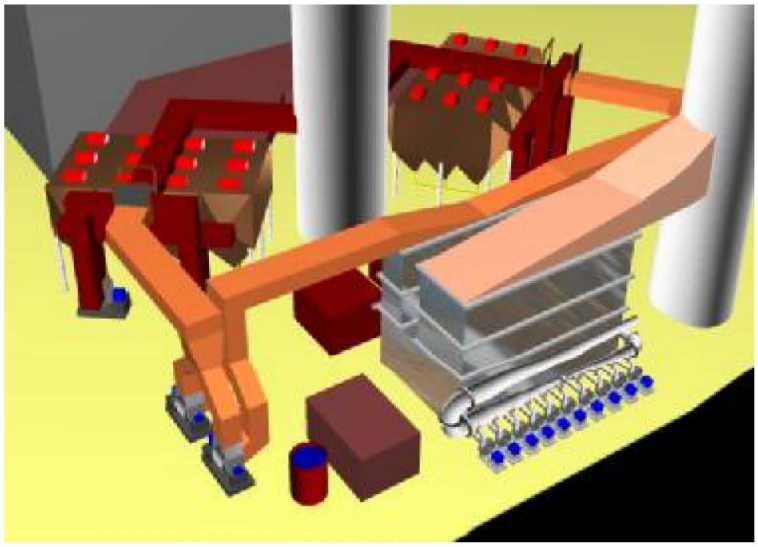

Figure 9. Layout of the new FGD system at Paradise Unit 3

As the gas leaves the first tower, it traverses the top of slurry in the reaction tank before entering the second tower. In the second tower, the flue gas passes co-current to the flow of the fountain spray and counter-current to falling drops of slurry.

The recycle pump bay is located in front of the second tower. The FGD system will require 11 slurry recycle pumps rated at 48,000 gpm. Four recycle pumps discharge into a common external recycle header which provide slurry for the first absorber tower which operates at about 21 fps gas velocity. Six recycle pumps discharge into a second common recycle header which provides slurry to a the second absorber tower. The second tower operates at about 15 fps gas velocity. The 11^{th} pump is located between the two recycle headers and provide spare capacity to either external header.

Each of the twin towers is equipped with a single level spray header. Low-pressure silicon carbide nozzles are used to provide a fountain-like spray reaching about 16 to 20 ft in height. The recycle slurry exits the spray nozzle much like a liquid rod that gradually disintegrates into very large spray droplets as the slurry decelerates and is pulled back into the recycle tank by gravity The fountain-type spray header design provides a very high degree of gas-to-liquid contact and a high degree of surface renewal that improves

the recycle slurry's neutralization capacity. The flue gas also contacts the slurry twice as the liquid exits the nozzles and ultimately returns to the reaction tank.
The low-pressure drop nozzle has no internals, a maximum free passage, and a very low-pressure drop. The nozzle is made from silicon carbide and, because of the low-pressure drop, experiences essentially no wear.

The single module, twin tower design has the added advantage of using top-mounted agitators, which also double as air spargers. This proprietary design, called the Air Rated Sparger or "ARS," is highly efficient in terms of mixing and oxidation. The new system includes three top-mounted "ARS," agitators. Adequate agitation is critical to scale-free operation. The ARS is also used to distribute the oxidation air. Compressed air is distributed to the horizontal arms of the agitator and sparged into the recycle slurry. This approach is highly efficient and requires a lower quantity of air compared to side entry agitators or a fixed grid sparger system. Hence, the power spent on agitation is offset by the reduction in power consumed by the oxidation air blowers. Two operating compressors and one spare air compressor provide oxidation air.

A pump suction deflection/screening plate is located in close proximity to the pump suction and spans the entire side of the reaction tank. The screening plate is installed to prevent air that is sparged into the reaction tank from being entrained into the recycle pumps and recycle piping.

After the flue gas exits the spray zone of the second tower, it passes through a two-stage vertical flow mist eliminator. The provided design is based on using a high velocity, high efficiency chevron type of mist eliminator. An 8 ft disengagement zone is provided between the top of the spray zone and the face of the first-stage mist eliminator. The provided disengagement zone, coupled with the large droplets produced by the fountain-type spray headers, results in a very low liquid loading to the mist eliminator, even at elevated gas velocities.

A fixed grid wash system is provided to wash the leading and trailing edges of the first mist eliminator and the leading edge of the second mist eliminator.

The proposed system is designed to operate in an open loop configuration and does not include any dewatering system other than reaction tank bleed pumps that will pump reaction tank slurry to a pond. The water in the pond is not reclaimed or reused in the process.

A wet stack will be provided to discharge the clean flue gases to the atmosphere.

A new limestone grinding system will be installed which will provide a limestone grind of 90% less than 325 mesh.

Summary

MHI introduced the DCFS system in the early ‘90s and, to date, more than 20,000 MW has been installed and/or sold. The DCFS system was specifically designed to provide absolute reliability as demonstrated by the numerous installations operating at 100 percent availability with a single a absorber module. The absorber tower is equipped with a single spray header which by design does not generate any wall erosion from spray impacting on the walls or any header to header erosion. The fountain spray provides a very efficient gas/liquid contact which is also demonstrated by the very high particulate removal provided by the system. The experience with high sulfur coals, very high removal efficiencies , high availability with a single absorber module is considerable. The first greenfield DCFS system in the U.S. is being installed at the TVA Paradise station which will go into operation in 2006. A second system is being installed at TVA’s Widows Creek station through a rebuild of the existing FGD system to the DCFS design. The Widows Creek DCFS system will be operation in late 2003.

Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD

Paper #33

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ABSTRACT

MHI's next generation scrubber, called the "Double-Contact-Flow-Scrubber" (DCFS), is unique technology that provides many features such as higher availability, less power consumption with high SO_2 removal efficiency, etc. This technology was recently selected by TVA for their Paradise Fossil Plant Unit 3 FGD plant that will be started up on early 2007. This paper will report on several of the latest outstanding commercial operating successes with this DCFS system including super high desulfurization performance (i.e., 99.9%) with a single absorber vessel, high gas velocity compact design with effective mist separation, and others.

The DCFS includes a single spray header located bottom of the scrubbing zone. Special nozzles made of SiC create a spray fountain pointing upward into the scrubbing zone. Flue gas is introduced below the spray header and turns upward 90 degrees and contacts the absorbent liquid in the scrubbing zone. Since absorbent liquid is sprayed upward and then falls by gravity, the sectional liquid density is twice that of conventional spray and/or grid packed system. This is why MHI calls it the "Double-Contact Scrubber. The Internal gas velocity is selected to optimize plant economics, but typically the gas velocity is between 10-15 fps which provides about 30% less foot print than a conventional system. MHI already has over 20 domestic and international operating installations of this DCFS technology, and each of these perform with greater than 99% availability.

In this paper, performance test data for the latest single-tower coal-fired application (a 600MW module) that started commercial operation on July 12, 2004 are reported. In addition, super high SO_2 removal efficiency (99-99.9%) under high inlet SO_2 conditions (2,000-3,000ppm) achieved by a single DCFS module and an extraordinary space-saving design related to its compactness feature are also introduced here.

INTRODUCTION

Mitsubishi Heavy Industry Ltd. (MHI)'s first FGD system was introduced in 1964, and today we have worldwide 163 installations, for a total of 55,000 MWe installed FGD capacity. Through continuous improvement and development in pilot and demonstration facilities, MHI's FGD system design has evolved over time from a design using a grid packed absorber tower to the current Double Contact Flow Scrubber (DCFS) that uses the highly efficient and reliable, fountain-type spray header design.

The DCFS has three configurations. The first is the co-current type DCFS in which the flue gas is introduced from the top of absorber and flows downward through the scrubbing zone. A second configuration is the counter-current type DCFS which introduces flue gas from bottom of scrubbing zone and directs it upward though the scrubbing zone. The third configuration is the combination of the co- and counter-current DCFS integrated on a single absorber tank. Typically, a co-current tower is selected when super high particulate removal efficiency (such as more than 90% or 10mg/m^3N(0.01lb/MMBtu) at outlet of absorber) is required . In this case, the flue gas velocity could be a maximum of 32 fps in order to achieve the required performance. Counter-current design is the most popular design for standard FGD requirement such as 95% to 97% SO_2 removal performance with medium- to high-sulfur coal. The twin tower design, which is the combination of co- and counter-current designs, is selected when both high particulate removal and extremely high desulfurization performance requirement (98% and over) for high sulfur coal are required. This twin tower design also can provide very stable operation in situations where quick load changes and rapid sulfur level changes can occur.

The twin tower design is always more reliable and efficient for stringent emissions requirement, but MHI has been making improvements to achieve higher performance in a single counter-current DCFS, which provides less initial investment (i.e., less foot print) with nearly zero SO_2 emissions. In the past 2 or 3 years, we have been successful in achieving ultra-high SO_2 removal efficiency (e.g., 99.9%) with a high inlet SO_2 using a single tower DCFS. This paper focuses on these new applications of single tower DCFS, and its development facilities.

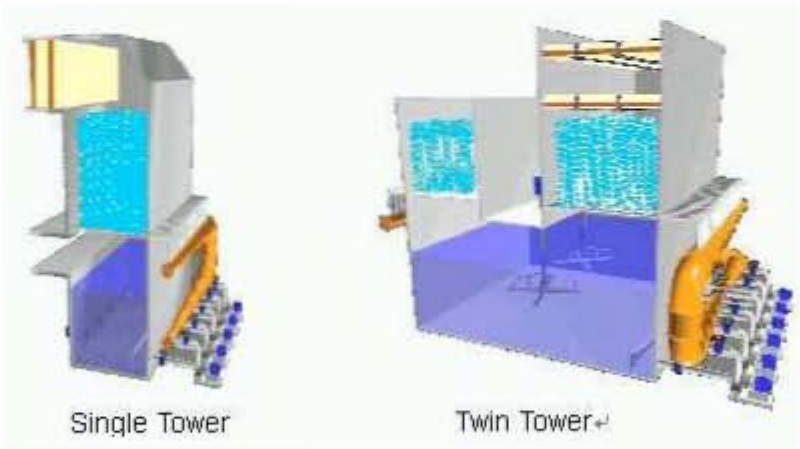


Figure. 1 ; Comparison between single and twin

SINGLE TOWER DCFS

Description of Double Contact Flow Scrubber (DCFS)

The flue gas enters the absorber from the side of the absorber tower through the wet-dry section at the breach of the inlet duct. The wet-dry zone is washed by fresh water at regular intervals. The flue gas is immediately quenched by the slurry spray as it enters the absorber.

Absorber recirculation pumps are typically located beside the absorber on the opposite side from the flue gas inlet. The external header goes up to the spray level and connects with the internal spray headers. On the internal spray headers, DCFS nozzles are placed pointing upward as shown in Figure 2. Since the nozzles are placed at one or a maximum of two levels, nozzle installation and maintenance work is extremely easy and quick. These nozzles have about 1 -1/2' opening so clogging of the nozzle is very unlikely, and, even if it happens, checking for nozzle pluggage is easy since nozzles are pointed upward.

Fig.2 DCFS spray and nozzles

At the top of fountain column, slurry is spread by the rising flue gas and forms well-mixed gas-liquid contact zone. This fountain or liquid column in the absorber contacts the flue gas as it proceeds co-current to the liquid spray and again counter-current as liquid returns to the reaction tank by gravity. That is why we called this system "Double Contact Flow Scrubber (DCFS)" .

The DCFS nozzles create an upward fountain, so no impingement of spray pipes and walls occurs. Also, as the spray is directed away from the inlet duct, no buildup in the inlet duct is experienced.

The reaction tank operates at 30 wt% solids, which increases solid retention time in the tank and promotes gypsum crystal growth, which results in significant reduction of gypsum scaling on the tank wall. Also, the high level of suspended solids in the reaction tank provides an elevated alkalinity level that enhances SO_2 absorption and makes the system more stable to sudden changes in inlet SO_2 loading.

SINGLE TOWER DCFS EXPERIENCE

Overview of Single Tower DCFS Experience

MHI has 11 single DCFS installations with a wide range of operating conditions as shown in Table 1. As one design advantage of the single tower DCFS, an alternate system that eliminates the air compressor/blower along with associated piping and side-entry agitators is introduced here. This proprietary design, called the Jet Air Sparger or " JAS," is MHI newly developed simple oxidation system, and is already installed and operated at some of these single tower DCFS.

Table 1. Experience table for Single tower DCFS

Year	Customer (Location)	Capacity	Gas source	Inlet SO2	Outlet SO2	SO2 removal
1993	Kashima South Joint Power Corporation (Kashima, Japan)	146×1	Oil-Fired Boiler	1,593	50	96.8
1997	Fukui Joint Thermal Power Co., Ltd. (Mikuni, Japan)	250×1	Oil-Fired Boiler	1,601	110	93
1997	Sumitomo Osaka Cement Co.,Ltd.(Ako,Japan)	100×1	Coal-Fired Boiler	1,298	48	96.3
2000	Nakayama Nagoya Joint Thermal (Nagoya, Japan)	149×1	Coal-Fired Boiler	496	26	94.8
2002	Hokkaido Electric Power Co.,Inc. (Tomatoh-atsuma #4, Japan)	700x1	Coal-Fired Boiler	882	42	94.6
2002	Kansai Electric Power Co., Inc. (Gobo #3, Japan)	600x1	Oil-Fired Boiler	554	4.5	99
2003	COSMO OIL Co., Ltd. (Yokkaichi, Japan)	223x1	Vacuum Residue Fired Boiler	3,433	17	99.5
2004	Tokyo Electric Power Company (Hirono, Japan)	600x1	Coal-Fired Boiler	639	24	96.2
2004	Nippon Petroleum Refining Co., Ltd. (Muroran, Japan)	99x1	Vacuum Residue Fired Boiler	2,909	50	98.3
2004	Nippon Petroleum Refining Co., Ltd. (Marifu, Japan)	149x1	Pet.Coke & Vacuum Residue Fired Boiler	4,087	25	99.4
2003	Kashima Northern Electric Power Co. (Kashima-kita #3,Japan)	300×1/2	Vacuum Residue Fired Boiler	2,060	50	98

For coal fired boilers, mercury emissions will be an important issue. Most recent measurements confirm oxidized mercury removal efficiency across the single tower DCFS to be over 90%.

Latest Coal-Fired Experience of Single tower DCFS

The latest FGD module provided is on the 600 MW coal-fired generation unit of Hirono thermal power station is. This is one of the largest single tower DCFS modules, and commercial operation started July 2004. Notably, MHI designed and supplied all equipment from boiler to stack through FGD . The system also includes direct feed type (no hydroclone) gypsum dewatering equipment and a wastewater treatment system designed to meet stringent Japanese regulations, and MHI optimized the total configuration of all of this equipment.

Figure. 3; Absorber tower outlook

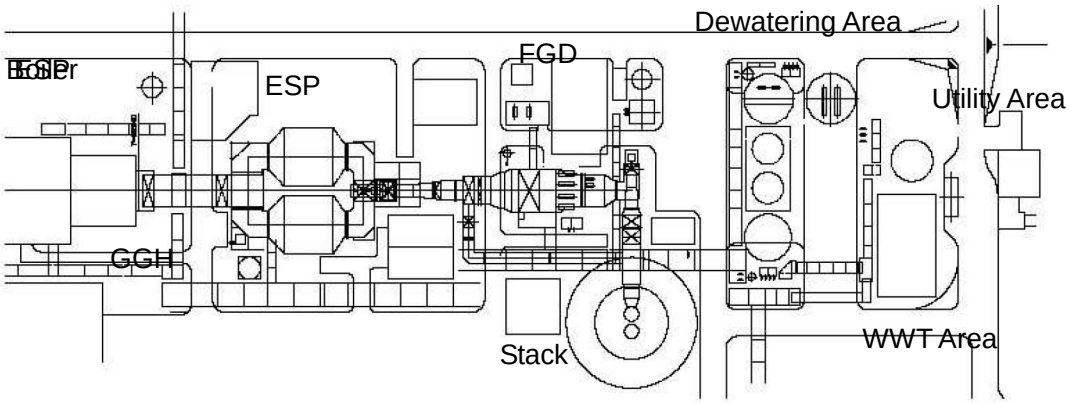


Figure 4; Hirono #5 Unit Overall Layout

Corresponding to the client's requirement of over than 96% desulfurization efficiency, MHI applied a single tower design to maintain a small footprint and simple configuration. As a result, the liquid-to-gas ratio is set at a relatively low value and results in lower power consumption. Moreover, the limestone stoichiometric ratio is also a relatively low value resulting in 94.2% gypsum purity.

Because of the 10,000mg/l chloride content in absorbent slurry, a resin lined carbon steel vessel was supplied instead of 6% molybdenum alloy to reduce initial investment (common practice in Japan). FRP internal spray pipes were supplied because of the no impingement characteristic of the DCFS spray. The external spray header was made of rubber lined carbon steel.

This FGD facility was turned over to the client on July 12, 2004 after successful trial operations during the August 2003 to July 2004 period. This coal-fired FGD project demonstrated that single tower technology is applicable and fully reliable for large coal-fired boilers.

Performance test results of Hirono Power Station's FGD facility are shown in Table 2. As can be seen, the actual desulfurization efficiency and particulate removal efficiency are 98.3% and 79.3% respectively.

Table 2. Hirono FGD Facility Performance Test Results

	Unit	Experienced value
Desulfurization efficiency	%	98.3
Particulate removal efficiency	%	79.3
Gypsum Purity	wt%	94.2

Ultra-High SO2 Removal Experience of Single Tower DCFS

COSMO oil Yokkaichi is an outstanding example of high SO_2 removal by a single counter current DCFS. Commercial operation at COSMO began in 2003, and the FGD system has achieved a cumulative availability of 100 percent since startup. The system is designed at 99.5% and operates at 99.9% SO_2 removal efficiency from VR fired flue gas (measured SO_2 concentration was 2,670 ppm). Measured outlet SO_2 concentration at the stack was only 3 ppm. In the past, such a high desulfurization capability has been considered impossible in a single tower design. This experience proves that the single DCFS can achieve over 99% performance as can the twin tower DCFS. The major reason for this high performance is the enhanced liquid-to-gas contact created and the high reagent reactivity from the 30wt% slurry concentration.

Figure. 5; Outlook of COSMO FGD

Space Saving Design of Single tower DCFS

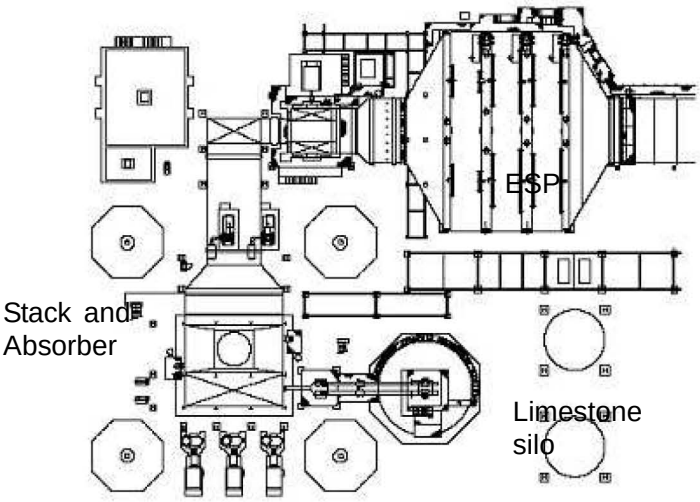
FGD systems for a petroleum refining company in Japan demonstrate a clearly differentiating space-saving advantage of our single tower, stack integrated DCFS design. In this design, the absorber tower is combined at the bottom of the stack and the absorber outlet is directly connected to the stack through the mist eliminator. For this stack integrated design, the FGD system performs like a part of the stack itself, and high reliability is mandatory. Single DCFS technology meets such a requirement and no by-pass design is selected as a result. In the site arrangement, other than the stack integrated absorber itself, the only required additional area is for limestone preparation and gypsum dewatering. Thus, the stack integrated design saves considerable space compared to a traditional flue gas treatment system. These compact single DCFS modules also show ultra-high removal efficiency (99% over) from a high SO_2-laden flue gas (over 2,500ppm) (see table 3 for measured performance).

Table 3. Measured performance of stack integrated FGD

Plant name	Boiler Capacity	Fuel	Flue gas flow rate	Inlet SO2	Outlet SO2	Desulfurization eff.
Plant A	149	VR +pet.coke	610,000Nm^3/h	2,850ppm	2.8ppm	99.9% (99.4%)
Plant B	99	VR	438,200Nm^3/h	2,590ppm	11ppm	99.6% (98.3%)

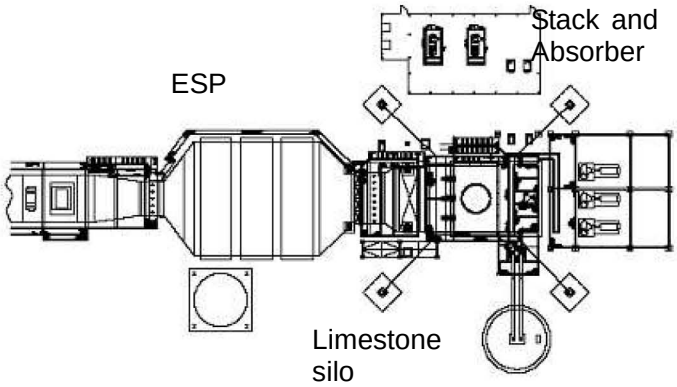
(Design value of SO_2 removal efficiency)

Outstanding compact layout and outlook of these stack-integrated Single DCFS is shown at Figure 6 and 7.



View

Figure. 6 ; Layout plan and outlook of Plant A



View

Figure.7; Layout plan and outlook of Plant B

FURTHER EXPERIMENTAL ACTIVITY

As shown above, the single tower DCFS configuration is effective in compacting and simplifying FGD design. As a result, MHI continues to develop the future technology of single DCFS and has constructed a 400 MW equivalent full-scale single DCFS test plant. MHI's objective in building this test equipment is to speed up the development of next generation SO_2 removal devices, and, additionally, to respond to future regulations that the SO_2 absorber tower may have to meet, such as mercury, PM2.5, etc.

The MHI Mihara works is the home of MHI's full-scale FGD fluid dynamics test rig, shown in Figures 8 and 9.

Figure. 8. Full scale FGD model.

Figure. 9. Inside of full scale model

This full scale wet FGD test facility is a pilot plant treating approximately 1,200,000 Nm^3/h-w flue gas using a single tower DCFS module.

The pilot plant includes a flue gas recirculation system with SO_2 injection that allows flue gas dynamic distribution testing and SO_2 removal performance testing, respectively. The pilot plant is also equipped with mist eliminator and related limestone preparation / gypsum dewatering systems. Hence, it is able to simulate the total FGD system under various conditions.

CONCLUSION

The DCFS has been developed as a highly reliable absorber to replace the conventional grid-packed absorber. The single tower DCFS design was applied in Japan for high SO_2 removal design and on coal-fired boilers because of its simplicity and compactness.

As the latest coal fired single tower application, the Hirono Power station FGD module started commercial operation on July 12, 2004. MHI supplied all equipment from boiler to stack and optimized it as a total system. Regarding desulfurization system performance, over 98% SO_2 removal performance and over 94% gypsum purity is achieved simultaneously by a single tower DCFS module. This experience should be firm proof of the single DCFS's applicability to achieve high SO_2 removal on a coal-fired boiler.

Further, at the Yokkaichi plant and, two FGD facilities of a petroleum refinery company with a simple stack integrated type design achieved over 99% SO_2 removal performance under high inlet SO_2 concentration conditions (2,000-3,000ppm). These performance proves not only the single DCFS's high flexible arrangement but its high performance capability as well.

From these latest operation results, we have a firm belief that these single tower DCFS type absorbers will largely contribute to further development of the desulfurization technology.

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KEY WORD LIST

Mitsubishi
DCFS
SO2
Removal
Single tower

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8/30/2004 – 9/02/2004
Washington, DC

FLOWPAC – Major WFGD Advance in Flue Gas Contact

Paper # 114

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Abstract

FLOWPAC is ALSTOM's reliable and high performance FGD absorber – designed to meet the current and future regulations for sulfur dioxide performance and equipment reliability. FLOWPAC has few moving parts (no agitators or pumps) and utilizes a cross flow tray design for optimal SO_2 mass transfer.

Regulators are challenging the envelope of conventional FGD equipment and a fresh look was needed. ALSTOM's research team launched a multi-year project to produce a state-of-the-art FGD absorber to address these challenges, using Designed for Six Sigma tools to evolve and improve the concept. Using the voice of the customer and failure mode effect analysis tools coupled with extensive pilot lab work, advances and simplifications to FLOWPAC have been realized. A single tank now accomplished where previously three tanks were required. A waterfall quench has replaced the prescrubber. The air lift replaces the function of the slurry recirculation pumps, oxidation blowers and agitators.

The paper will briefly recap the first ALSTOM FLOWPAC unit successfully installed in 1996 at KKAB located in Karlshamn, Sweden on a 340 MW heavy oil fired boiler. The paper will then discuss the evolution and simplifications to the FLOWPAC scrubber. The paper will conclude with a look at recent developments and testing and provide a look at conceptual arrangements that illustrate the low profile of the FLOWPAC absorber.

Although FLOWPAC is ideally suited for units combusting fuels with a medium to high sulfur content that require high SO_2 removal efficiency, the absence of large pumps, piping, spray nozzles and resulting low maintenance requirements

make FLOWPAC an attractive option for any FGD application where high SO_2 removal efficiency is required.

Introduction

The Karlshamn Power Station is comprised of three heavy fuel oil fired 340 MW units. The units operated as base load units from the 1969 to 1977 period. Today, 80 employees operate them as peaking units. Under normal circumstances, Sweden's electricity needs are met by hydropower and nuclear power. The role of the Karlshamn units today is to serve as peaking and standby power that can be started up and deliver electric power on short notice. These units provide the security to the Swedish electric supply providing power during extremely cold weather periods, augmenting hydropower in an extremely dry year, or when an unplanned service to a nuclear must be undertaken.

Karlshamn 3, on the right, is equipped with the Flowpac FGD system

The Swedish National Licensing Board in the late 1980's implemented tighter regulations for improved environmental protection. These regulations became effective in 1997 and required the reduction of flyash, nitrogen oxides and sulfur. The utility had to obtain a permit to operate at the emission rates established by the National Licensing Board. Any emission between zero and those permitted are taxed. As a result, the utility made significant environmental investments at the power station to permit the firing of low cost high sulfur heavy fuel oil on unit 3 to limit the taxes (or fees) resulting from emissions. As the emissions rates were defined as a bubble for all three units, Karlshamn units 1 and 2 with very low utilization could continue with more costly low sulfur heavy oil (0.15 – 0.3 %Sulfur).

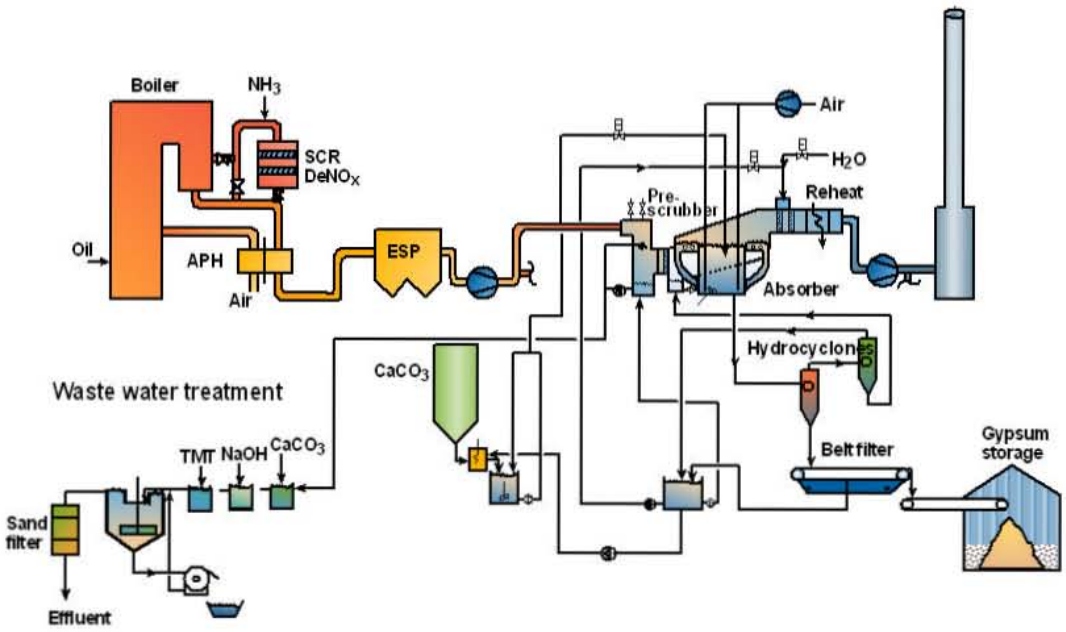
The emission conditions established by the National Licensing Board for the Karlshamn Power Station block were as follows:

- Sulfur (S) 25 mg S/MJ or 175 mg SO_2/NM^3 or 62 ppm
- Nitrogen oxides (as NOx) - 70 mg/MJ or 250 mg/NM^3 or 120 ppm
- Flyash – (Karlshamn Unit 3 only) – 90% collection efficiency before the desulfurization plant.
- Ammonia shall not exceed 5 ppm.
- Oil in water effluent, annual mean value shall not exceed 10 mg/l

All emissions above zero are subject to emission fees (taxes) as follows:

- 40 SEK per kg NOx - 70 mg/MJ at full load corresponds to 8000 SEK (~ $800) per hour
- 27 SEK per 0.1% Sulfur content and m3 - 25 mg/MJ at full load corresponds to 2000 SEK (~ $200) per hour

Kjell Nolin, the plants mechanical maintenance manager, was very familiar with conventional open spray tower WFGD systems but he had a better idea. Fans and compressors and small pumps are common to the facility; large slurry pumps were not. The idea was born to use a bubble bed sieve tray to obtain a very efficient gas to liquid contact without the use of large recycle pumps. This would eliminate the use of large, high head absorber recycle pumps. FLOWPAC was born.

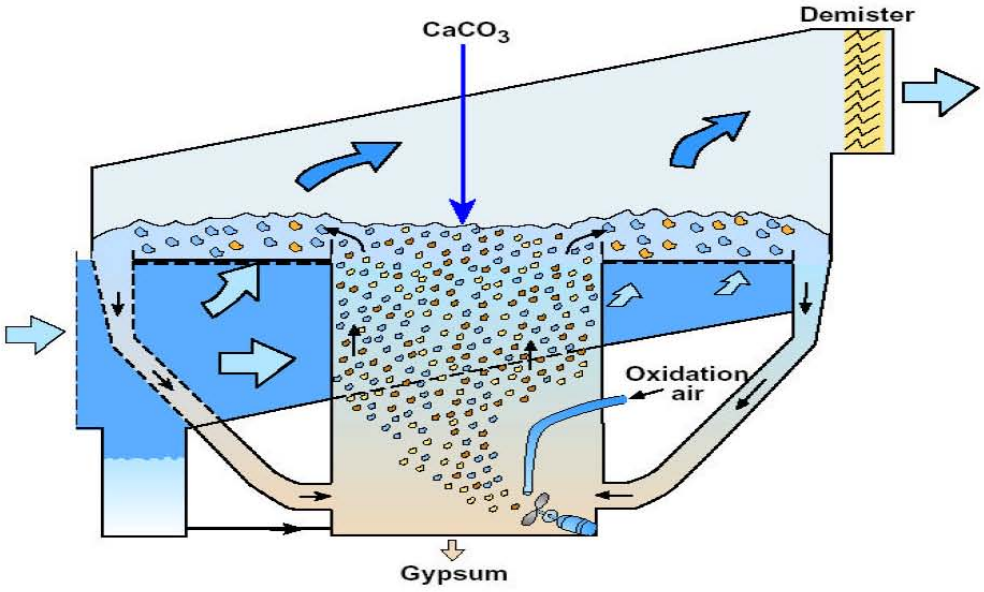


Flow Diagram for Karlshamn Unit 3

The FLOWPAC absorber differs in the flue gas contact zone. The preparation of the reagent lime or limestone for use in the absorber is the same as for a

conventional open spray tower system. The dewatering of the oxidized slurry with hydro cyclones and belt filters is the same as a conventional open spray tower system. The gas contact zone is radically different - and the heart of the WFGD system.

The flue gas enters the absorber under the sieve tray, passes up through holes in the sieve tray and rises through a turbulent slurry limestone bed. This turbulent bed allows intimate contact between liquid and gas, providing excellent conditions for SO_2 absorption and natural oxidation.



Section of the absorber.

The sieve tray encircles the absorber recycle tank. The recycle tank is agitated and supplied with oxidation air. The air lift effect generated by the difference in densities when oxidation air is introduced into the recycle tank eliminates the need for large absorber recycle pumps. The expanding slurry rises in the recycle tank and flows out across the sieve tray and is suspended by the flue gas. When it reaches the circumference of the sieve tray it flows to the down comer, where the dispersed gas is released, causing an increase in density. The 5-10% density difference between the slurry with dispersed air and the pure slurry generates the circulation of fresh slurry.

One of the strengths of the FLOWPAC cross-flow sieve tray is the excellent gas-liquid distribution inherent in this design. Other mass transfer devices such as a spray tower require high L/G ratios to compensate for the poorer distribution of gas and liquid (sneakage). Spray towers have used performance enhancement plates or wall rings to obviate the sneakage occurring at, for instance, the inner

wall. The FLOWPAC sieve tray has no sneakage path; all the flue gas comes in contact with and passes through a slurry bed.

Reagent addition to the FLOWPAC tray is done directly to the absorption zone rather than the reaction tank. This in combination with the high turbulence occurring in the slurry bed on top of the sieve tray achieves very high SO_2 efficiencies and almost full utilization of the limestone with little sensitivity to pH changes, and complete sulphite oxidation. The contact of flue gas with the slurry assures excellent removal efficiencies of >99%, and collecting efficiencies greater than 99.5% with the use of adipic acid.

Absorber internals with empty reaction recycle tank.

FLOWPAC sieve tray

Intimate contact of the flue gas passing through the slurry bed on the sieve tray also has shown additional benefits of high SO_3 removal, with efficiencies of 70% reduction having been measured. The violent agitation produced by the flue gas passing through the slurry bed and the intimate contact of the flue gas with the liquid also captures fine particulate.

Absorber in operation

The slurry on the top of the bubbling bed, - froth or foam - means fewer mist particles are carried from the bed of slurry on the sieve tray to the mist eliminator. This very low liquid entrainment produced a problem-free mist eliminator operation with reduced flushing, and thus lowered auxiliary energy consumption compared to a conventional spray tower absorber

Mist Eliminator in FLOWPAC Outlet

The low overall height of the FLOWPAC due to lack of large recycle pumps and spray banks allows the inspection and service of the system internals to be inspected without scaffolding.

Outside of FLOWPAC absorber at Karlshamn, showing two of the eight downcomers.

The simple FLOWPAC design was created from an owner perspective. The FLOWPAC does not require large recycle pumps with large motors, gear sets and mechanical seals. The space these pumps require near the absorber and in the storeroom for spare parts. The large pumps also generate a fair amount of noise. Eliminating these large pumps also eliminated an operational sequence of draining and flushing the large pipelines. The lack of these large recycle pumps reduces operating and maintenance requirements.

Karlshamn FLOWPAC Performance

	Design	Measured
Sieve tray bed height, inches	13.7	11.8
Oil S content, %	3.5	2.5
SO_2 Inlet, ppm	1950	1350
SO_2 Outlet, ppm	35	10
SO_2 Removal, %	97.4	99
SO_3 Removal, %	No Guarantee	~ 66 - 70

Recent Operation of Karlshamn

From November 2002 to Mach 2003, the Karlshamn Unit 3 was operated for 2152 continuous hours while firing a heavy fuel with an average sulfur content of 2.4%. The SO_2 emissions during this period were kept to 21 mg/Nm3, which is, a SO_2 efficiency of 99.5% with an S efficiency of 99%. During this period the FGD system was 100% available.

In April of 2004 additional SO_3 reduction tests were conducted at the Karlshamn Power Station. These tests were used to confirm early results that had shown SO_3 reduction across FLOWPAC to be in the 66% to 70% range.

FGD Inlet SO3 ppmv @3% O_2	FGD Outlet SO_3 ppmv @ 3% O_2	% Reduction
29.5	8.2	72.2
34.9	10.7	69.3
32.2	10.2	68.4
32.9	12.8	61.1
27.7	9.7	65.0
31.9	9.8	69.3
31.5	9.5	69.7
	Average Reduction	67.8

FLOWPAC has shown that at Karlshamn when firing oil, a reduction in SO_3 is achievable. These tests confirmed the earlier reported data with a FLOWPAC absorber pressure drop ranged between 16 to 20 inches w.c.

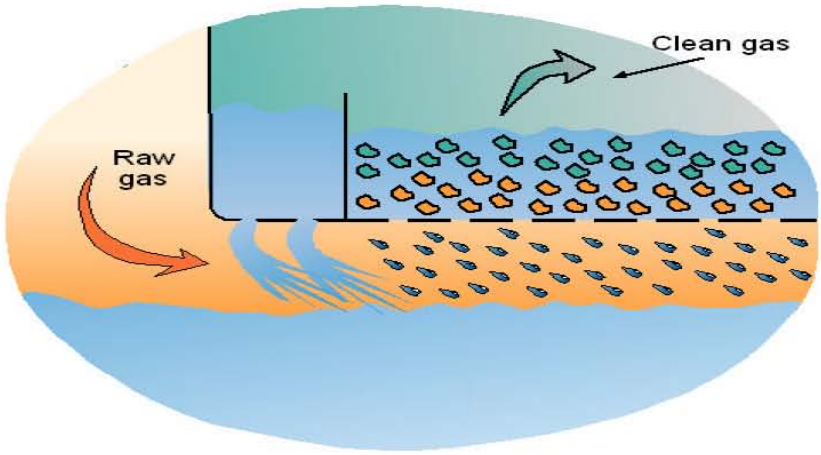
FLOWPAC - Improvements

The FLOWPAC team used Six Sigma tools to optimize the system design resulting in three major advances to FLOWPAC.

The separate prescrubber has been eliminated thus the integration of flue gas quenching and the mixing of gypsum slurry in one vessel or slurry tank was achieved.

Flue Gas Quenching

An airlift now raises the slurry to a quench trough; a curtain of slurry falling from the quench trough provides a defined wet-dry zone. The flue gas must pass through this curtain of slurry on the way to the underside of the sieve tray. The waterfall curtain provides a liquid cloud saturating the flue gas and ensures the wetting of the sieve tray underside.



Flue Gas Quenching

The FLOWPAC absorption tank is now a single tank collecting the quench slurry, any sieve tray seepage and containing the recycled circulation slurry. The tank is shaped with sloped sidewalls to direct the slurry to a tank base area. In the tank bottom two parallel plates form the main airlift channel where oxidation air is added.

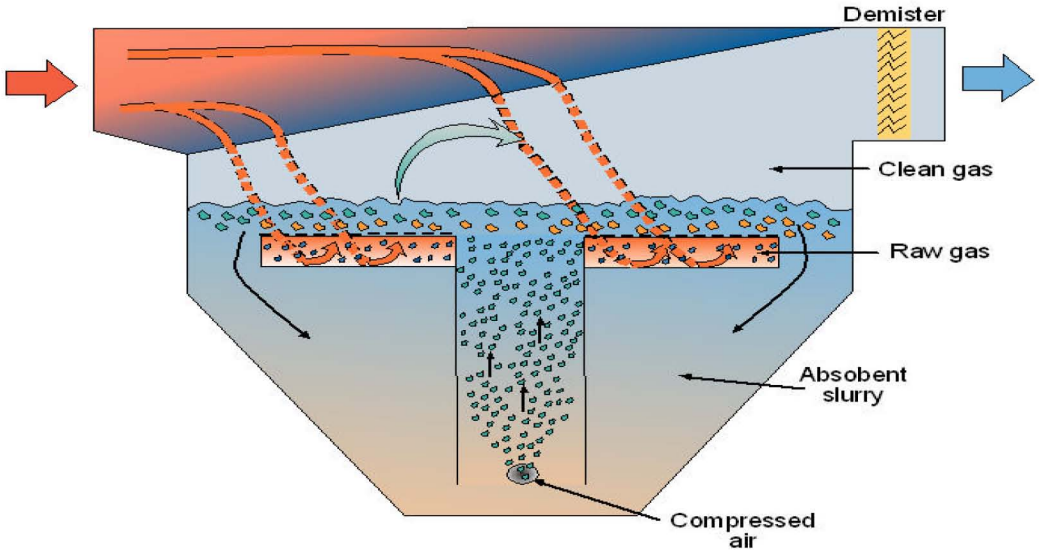
Oxidation, Agitation and Air Lift

This oxidation air is admitted between the two parallel air lift plates. The oxidation air is focused to a defined portion of the absorber recycle tank, the main air lift. The oxidation air produces a differential in liquid densities lifting the slurry to the elevation of the sieve tray. The flue gas supports the slurry on the sieve tray as the flue gas passes up through the bed of slurry. When the slurry reaches the edge of the sieve tray the slurry collapses falling back into the absorber tank. A gas seal in the absorber recycle tank prevents sneakage of untreated flue gas.

The slurry that has been lifted or removed from between the air lift plates must be replaced, therefore a circulation is established in the recycle tank. The unique shape of the absorber recycle tank along with CFD studies, lab and pilot tests have confirmed the shape and circulation effects eliminate the need for agitators in the base of the absorber tank. These tests were utilized to study the slurry circulation characteristics for different crystal size distribution of precipitated gypsum and the settling that would occur in different shaped absorber recycle tanks. The CFD model showed that oxidation air induced circulation and a properly shaped vessel would keep the gypsum suspended. These tests established design rules for the shape of the tank to avoid local settling. When the unit is placed in standstill, the flue gas fan and the oxidation air can be shut off. Prior to start of the flue gas fan, the oxidation air spargers are flushed with supernate drawn from the top of the recycle tank. Restart from a 30-day standstill has been

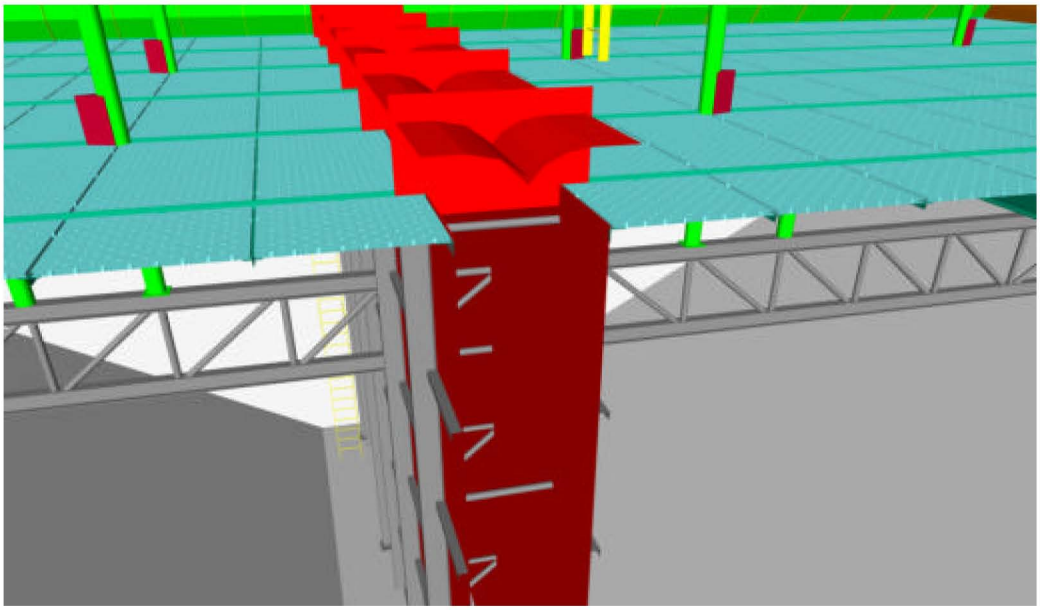
tested and demonstrated in a 50 MW size lab facility at various solid densities in excess of 30% solids.

Unlike an open spray tower where sneakage can occur at the wall of the absorber or at the junction of overlapping spray nozzles, all of the flue gas passing through the FLOWPAC absorber must contact slurry as it passes through the sieve tray and the bed of slurry on the tray.



Section through FLOWPAC quencher and absorber

The edge of the sieve tray has a throttle to permit the control of the sieve tray bed height. This provides the operator the ability to dial in the SO_2 removal capability of the FLOWPAC.

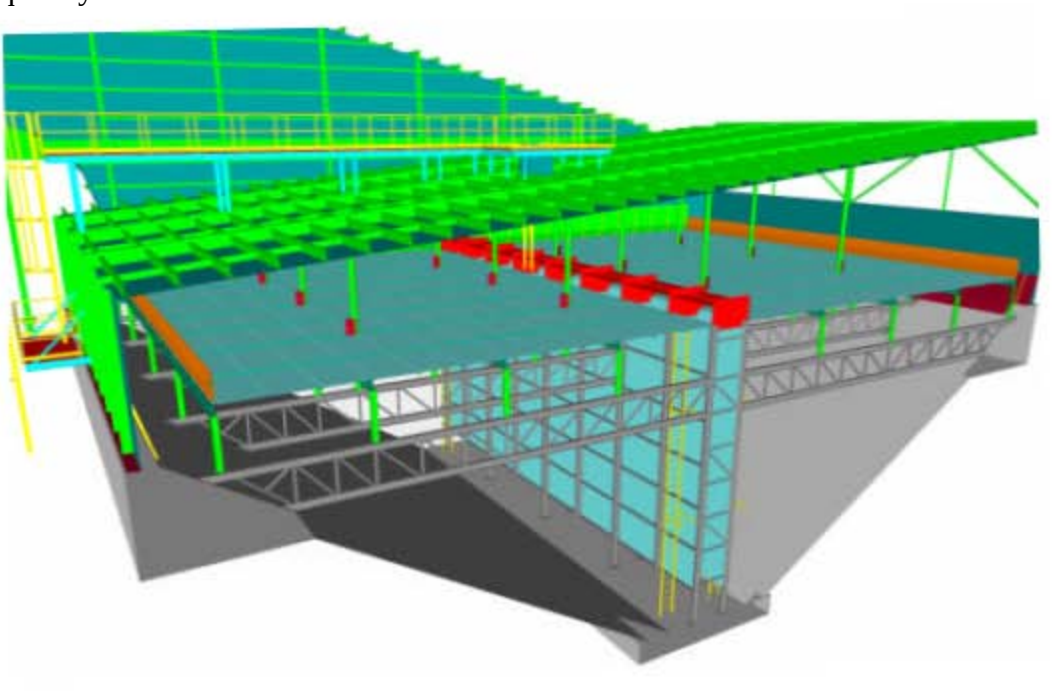


Air lift and Sieve Tray

Erection and Inspection

The sieve tray in the FLOWPAC absorber occupies one elevation. This renders it easier to build in a parallel construction sequence, unlike an open spray tower with multiple levels of spray headers that require a series building sequence. The single elevation has all the advantages of easy access for inspection and maintenance without the need to install temporary scaffolding. The internals are open surfaces with no complicated seals.

The foot print at grade of the FLOWPAC absorber is similar to that required for an open spray tower solution. However, a big difference exists in the overall height requirements. The FLOWPAC unit is significantly shorter in height. This low profile along with large, shop-fabricated pieces allows the unit to be built quickly and with the use of smaller cranes.



Elevation slice of FLOWPAC

Summary

The main characteristics of the new absorber are as follows:

- Very high SO_2 collecting efficiency,
- Almost zero SO_2 emission with adipic acid addition,
- High SO_3 and particle collection efficiency,
- No problems with scaling or corrosion,
- Lower auxiliary energy consumption than a spray tower absorber,
- Lower maintenance and supervision costs due to lower height, absence of large recycle pumps and piping,

- Minimum entrainment of droplets resulting in improved droplet eliminator performance with reduced flushing requirements.

The squat profile of the absorber vessel, the fewer large pieces of rotating equipment to install, and pipe and wire, all had a very positive impact in reducing the field man-hours to install the complete system.

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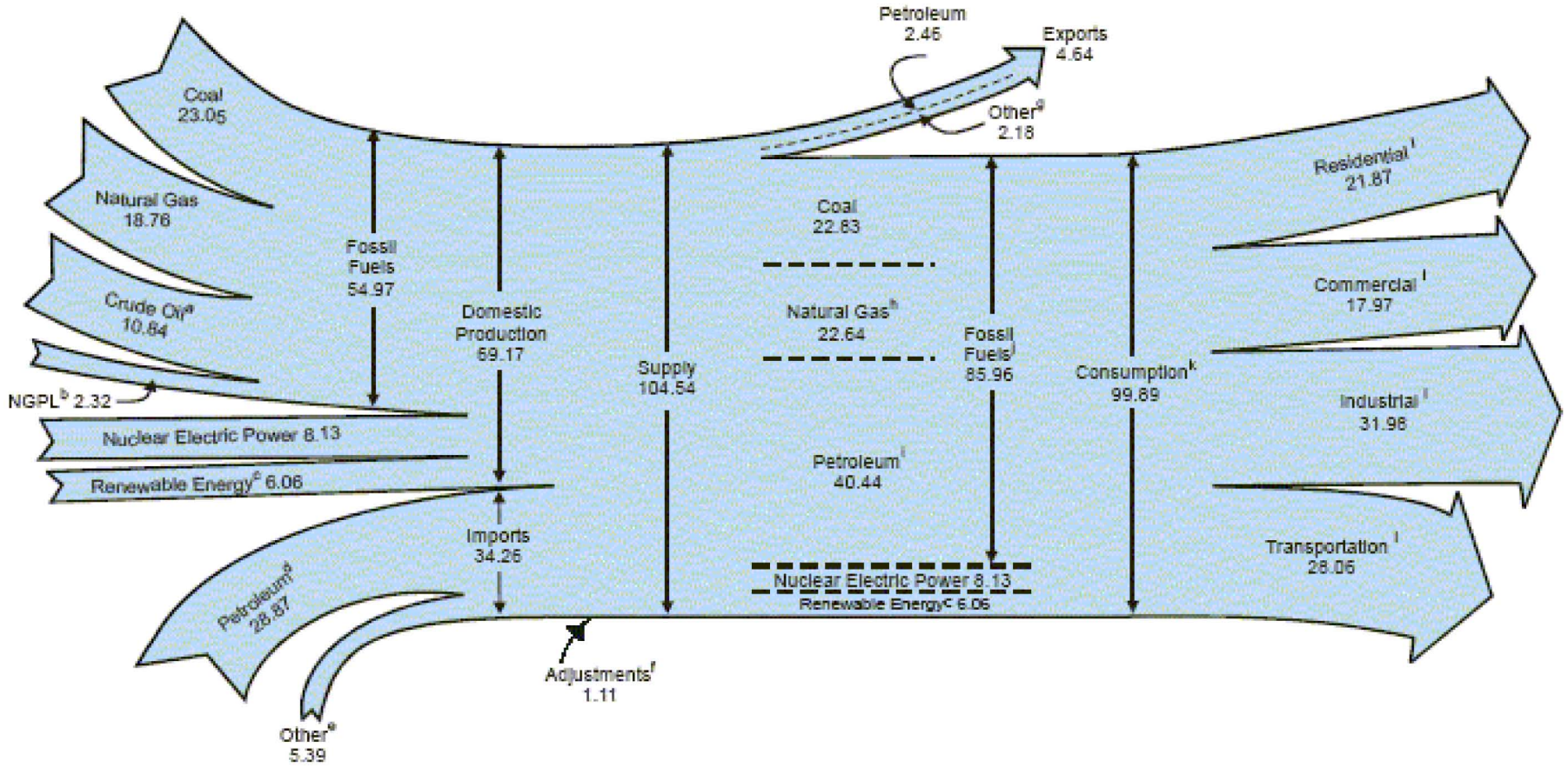
The CURC-EPRI
Clean Coal Technology Roadmap

Why Coal?
Meeting America's Energy Needs

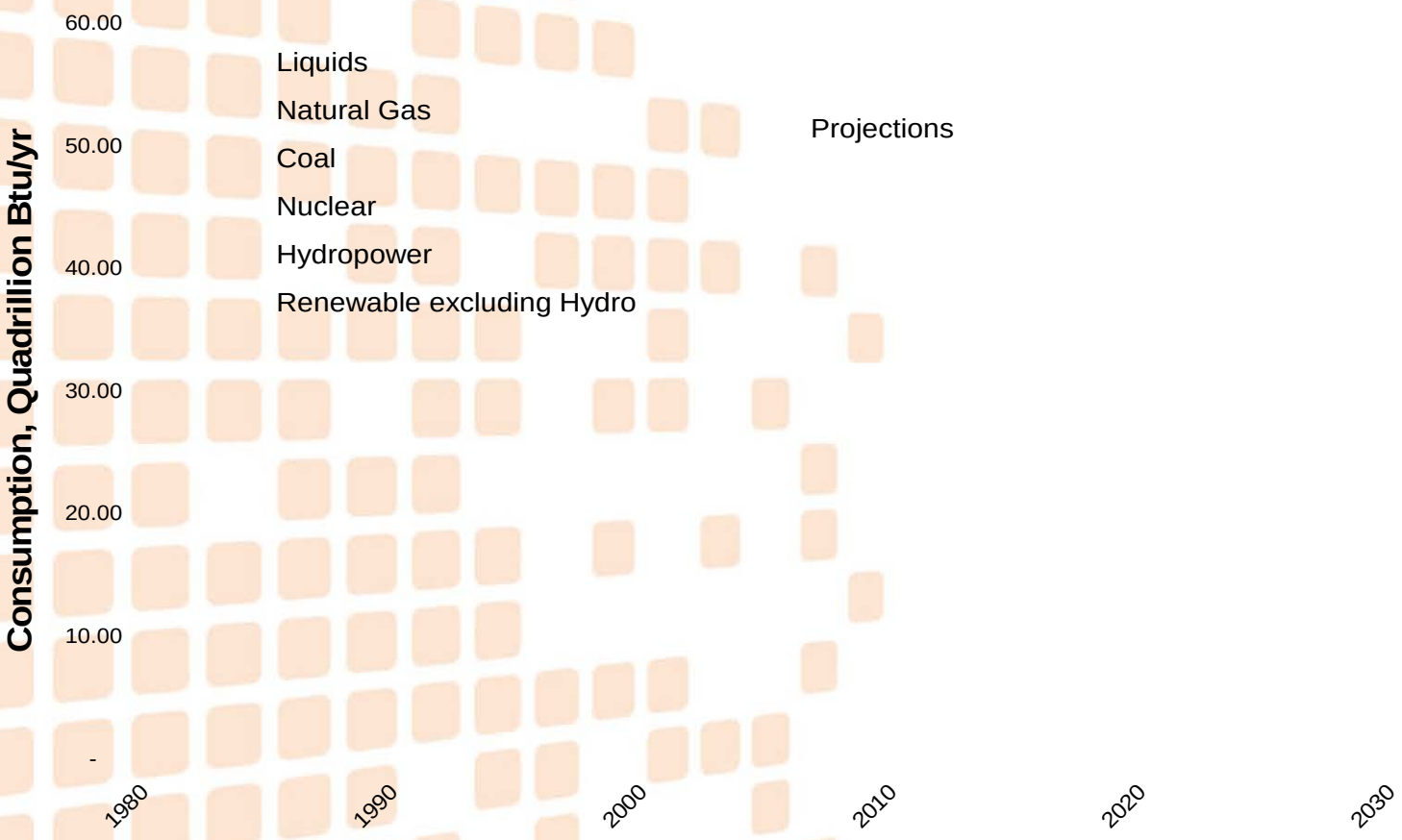
Coal Ranks 1st Supplying One-Third of U.S. Energy Production

Data are in Quads (quadrillion Btu's per year)



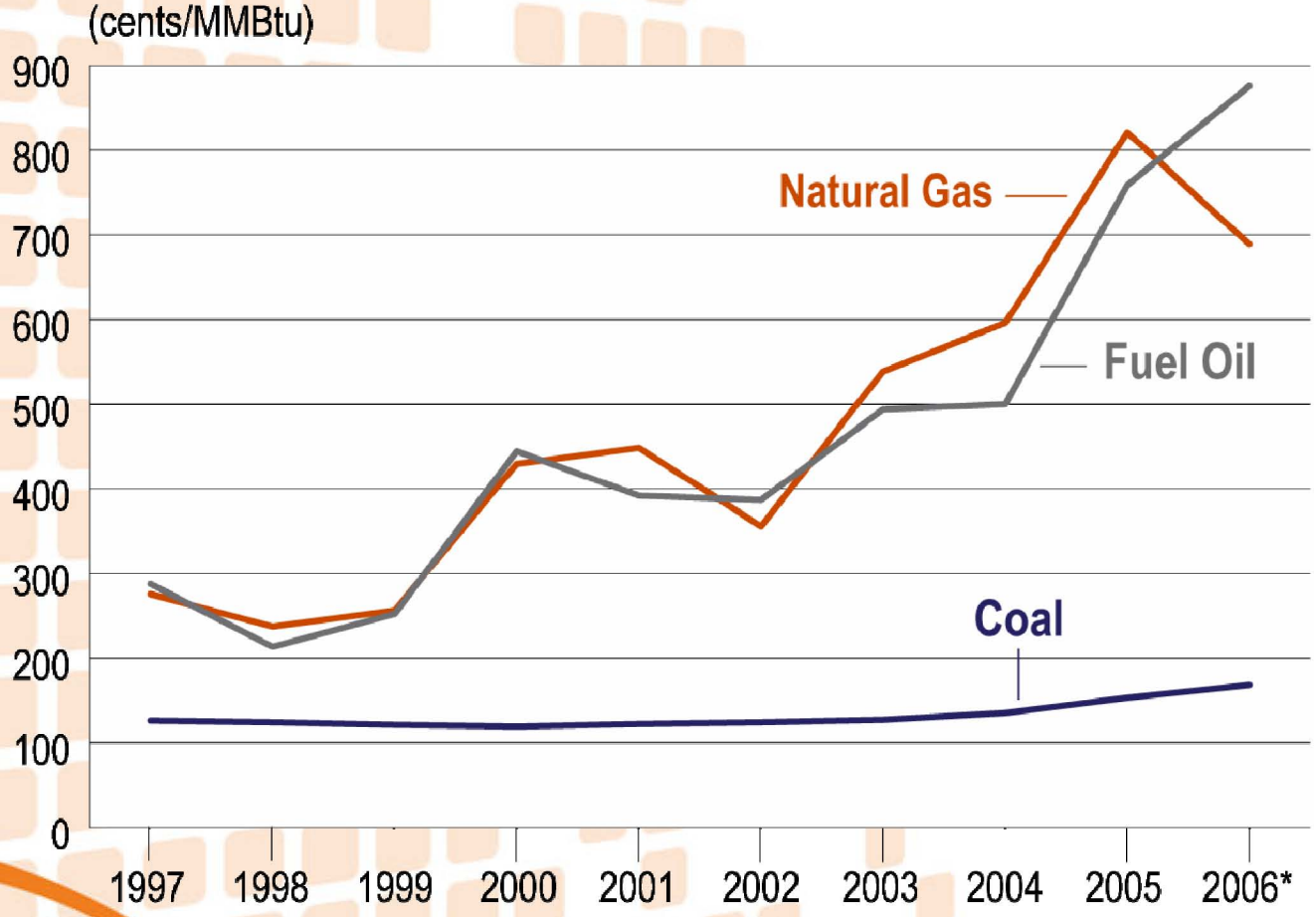
Source: EIA AER-2005

Coal ranks 2nd in consumption in U.S.



Source: EIA AEO-2007

We Use Coal Because It Is Economical



The years 2002 and beyond include data for electric utilities, independent power producers, and commercial and industrial combined heat and power producers. The years prior to 2002 include data for electric utilities only.

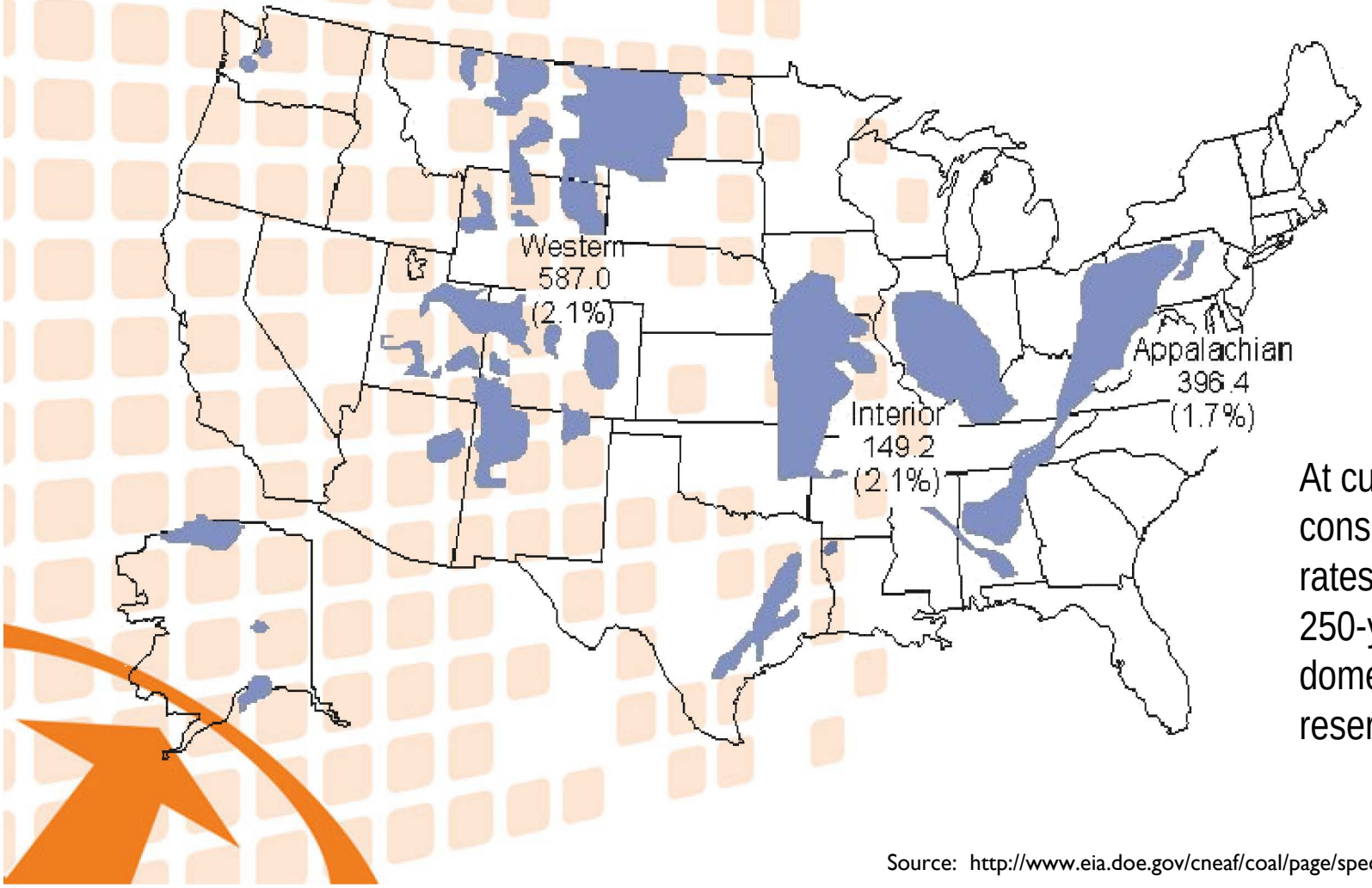
Note: *Through November 2006

Source: U.S. Department of Energy, Energy Information Administration (EIA).

Coal Is Plentiful and Disbursed Throughout the U.S.

Coal Production, 2005: 1132 M tons

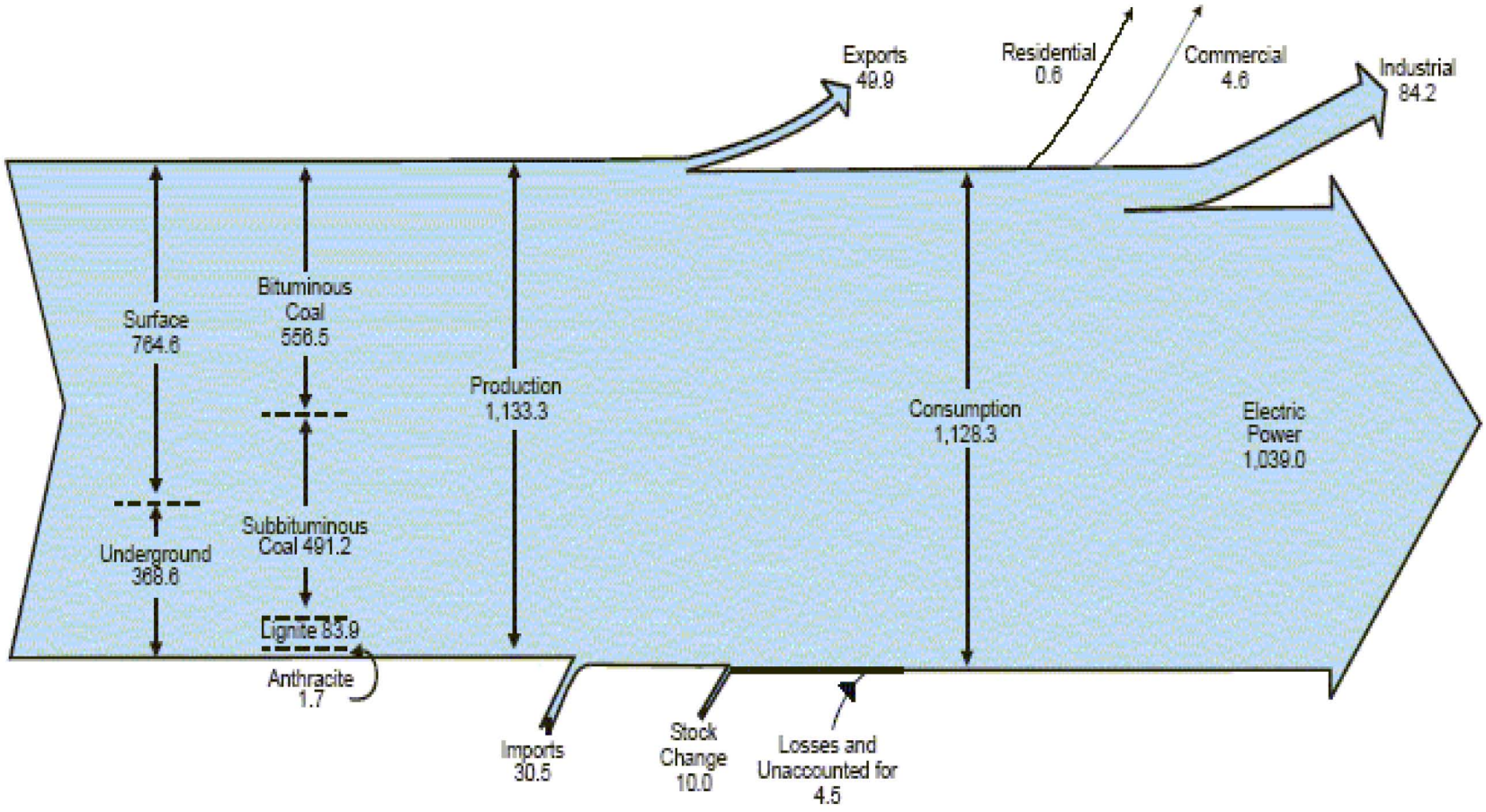
(Million Short Tons and Percent Change from 2004)



At current consumption rates, we have a 250-year supply of domestic coal reserves.

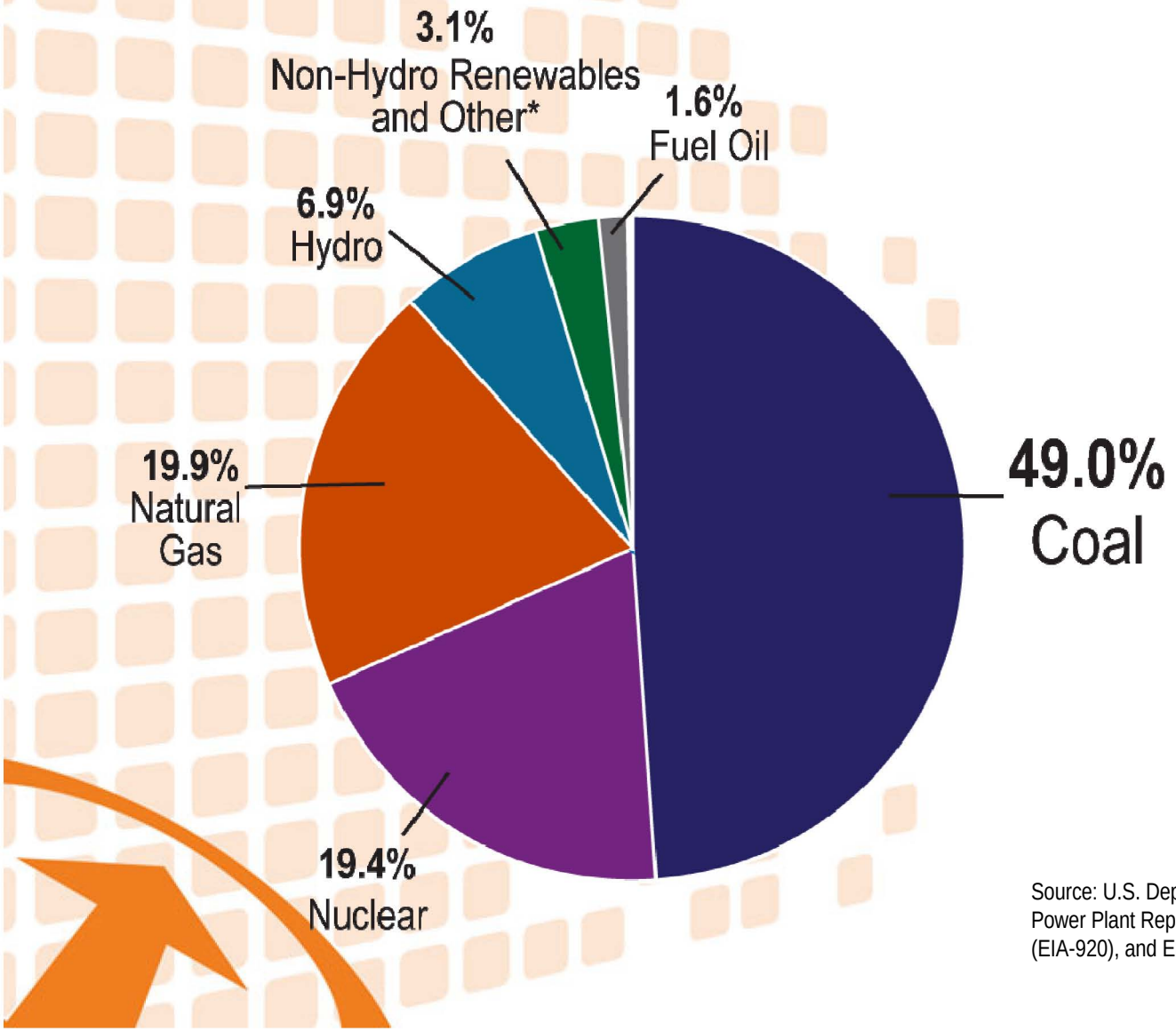
Source: http://www.eia.doe.gov/cneaf/coal/page/special/fig1.html

Nearly 90% of U.S. Coal Is Used To Produce Electricity



Source: EIA Annual Energy Outlook 2005

Over 49% of Electricity Produced In the U.S. Is From Coal

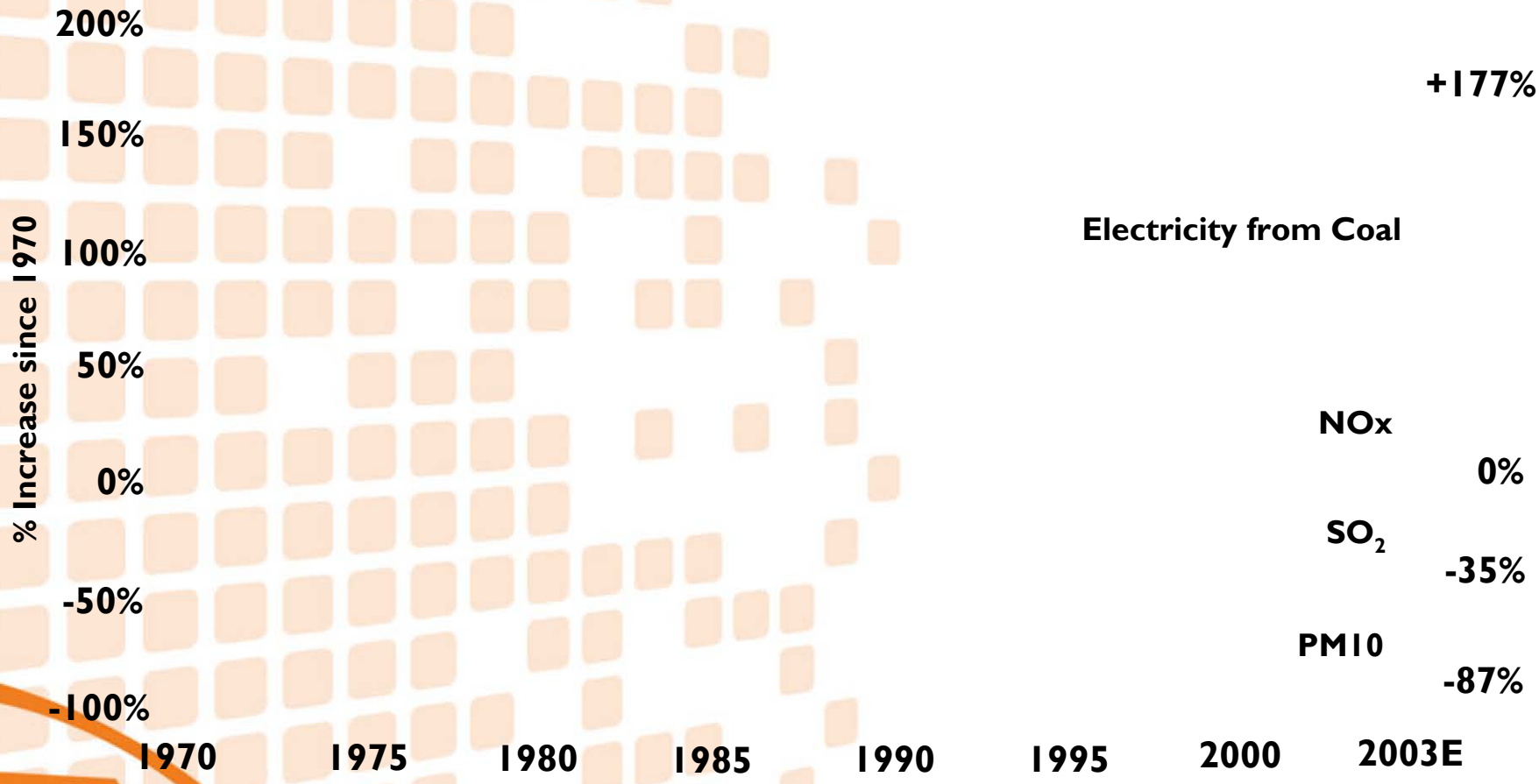


* "Non-Hydro Renewables and Other" includes generation from solar, wind, geothermal, biomass, hydrogen, batteries, chemicals, non-wood waste, purchased steam, sulfur and miscellaneous technologies.

Source: U.S. Department of Energy, Energy Information Administration, Power Plant Report (EIA-920), Combined Heat and Power Plant Report (EIA-920), and Electric Power Monthly (2006 Preliminary).

Coal - Increasingly Clean

Changes in Coal-Based Electricity & Emissions Since 1970



Source: EIA Annual Energy Review 2003 (Sept. 2004), EPA National Emissions Inventory Trends (Dec. 2004)

Benefits of Clean Coal Technology Development

- Greatly reduced emissions from power generation:
  - Sulfur dioxide, nitrogen oxides, mercury, particulate matter; less water consumption; less solid waste generation, or greater utilization as byproducts.
- Lower cost power, allowing coal to displace higher priced fuel like natural gas
- Gasification-based systems can also produce transportation fuels and other products
- In the future, the ability to cost-effectively capture and store CO_2

Challenges to Continued Coal Use

- Environmental Concerns and Climate Change
- RD&D Needs:
  - Near zero emissions of criteria pollutants
  - Increased efficiency
  - Cost-effective capture and storage of CO_2

The CURC-EPRI Roadmap

Cleaner, Affordable, More Efficient Energy from Coal

Roadmap Technology Areas

- Gasification
- Advanced Combustion
- Turbines
- Fuel Cells
- Existing Plants
- Carbon Management
- Advanced Research
  - Materials Research Needs
- Coal-based fuels

Timeframe: 2025

Focus: Power generation

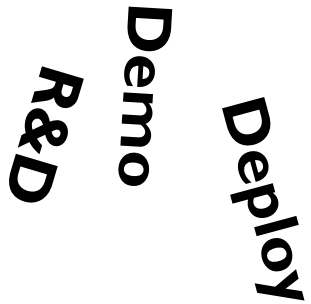
Roadmap Focus Upon CO_2

- New technology roadmap includes CO_2 capture and sequestration
  - Impact on performance, capital cost and COE
  - Technology path and R&D cost
- All technologies designed to produce CO_2 at the plant gate at standard conditions
- CO_2 Storage (i.e., sequestration) is a separate roadmap element

The Guide to Improved Technology Is the "CURC-EPRI Clean Coal Technology Roadmap"

- The Roadmap Story - with successful technology development and increased federal funding, future PC and IGCC systems will be highly competitive, and both will be able to cost effectively capture and store CO_2.
- Current R&D funding is inadequate, and demonstration funding is completely inadequate!

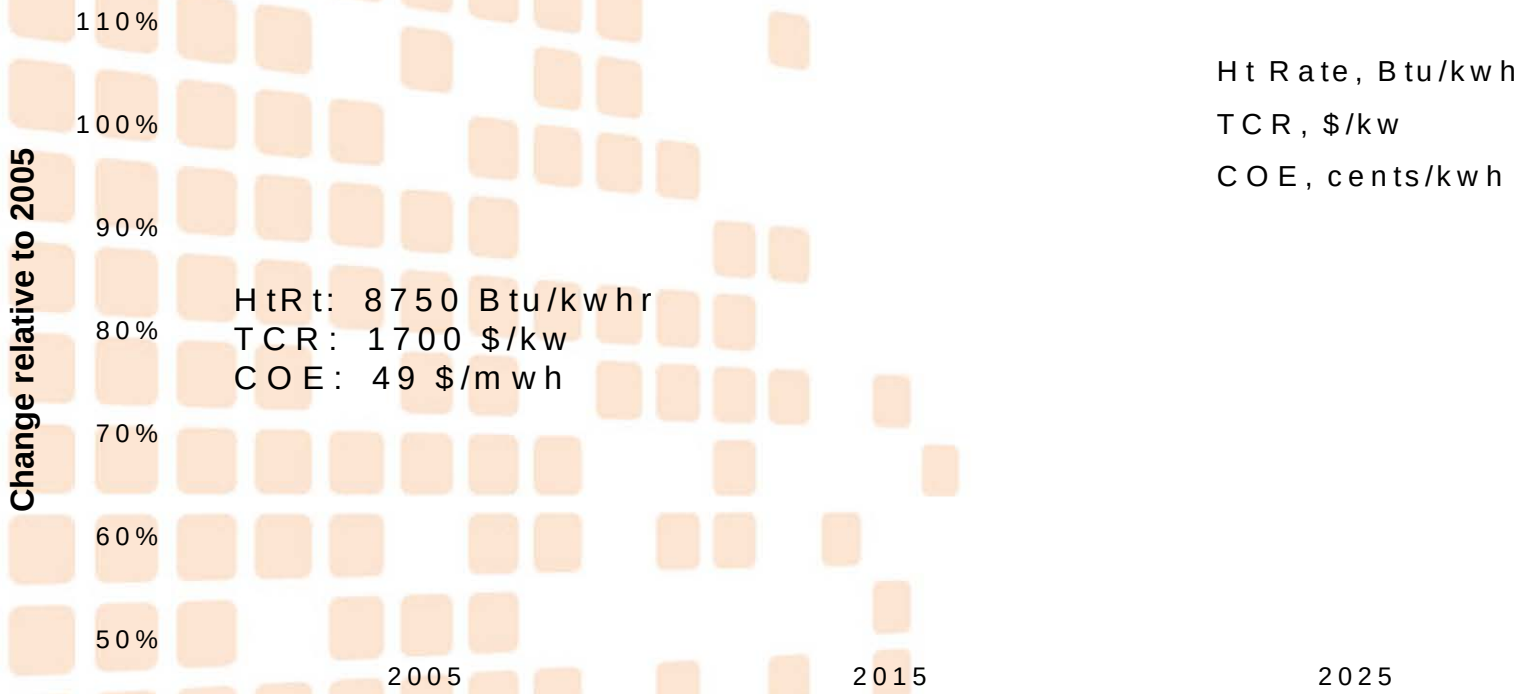
Need **ALL** 3 elements to successfully deploy new technology



Emission Performance: An order of magnitude reduction for traditional pollutants by 2025.

PC and IGCC Systems	Year	
	2005	2025
Emissions		
PM, lbs/MWhr	0.09	0.01-0.02
SO2, lbs/MWhr	0.8-0.3 (90-99%)	0.07-0.01 (98-99.9%)
NOx, lbs/MWhr	0.5-0.4	0.2-0.1
Mercury, %	> 80%	98-99%
CO2, lbs/MW-hr	1770-1940	1410-1670
Efficiency, Btu/kWh (HHV)	38-39%	44-49%

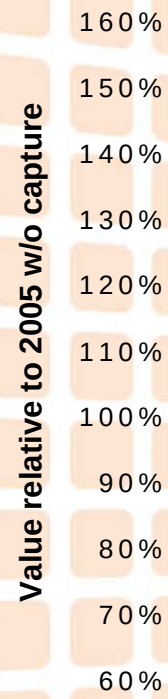
Technology Progress without CO_2 Capture



Necessary Technologies

	2015	2025
IGCC	-Improved refractory -Gasifier scale-up -G to H Class CTurbine -ITM Oxygen	-Warm gas cleanup -CO2/Slurry feed or dry feed -Fuel Cell hybrid
PC	-1150 F UltraSupercritical -Materials	-5000 psig / 1450 F USC -Materials

Technology Progress with CO_2 Capture



Baseline Conditions, 2005

Ht Rate, Btu/kwh
TCR, $/kw
COE, cents/kwh
COE with storage

	2005	2015	2025
Necessary Technologies	IGCC	-Demonstrated C storage -Hydrogen turbine	-Membrane CO2 separation -Multi-pollutant disposal / sour gas water shift
	PC	-Advanced Sorbent CO2 capture (e.g., chilled ammonia) -Oxy-Firing	-Advanced sorbents -Chemical looping

Summary of Roadmap Technical Needs

- Existing Plants
  - Demonstrations of Hg controls
  - Hg compliance monitors
- IGCC
  - Improved reliability/flexibility of gasifier
  - O_2 separation
  - H_2 turbines and fuel cells
  - Carbon capture
- Combustion
  - Advanced materials for USC
  - Oxy-Firing
  - Carbon capture
- Turbines
  - Higher temperature operation
  - Hydrogen compatibility
- Fuel cells
  - Decrease cost
  - Increase size
- Carbon Storage
  - Large scale, long term demos
    - 3 sites ~ $160M + $500M for CO_2
  - More sites than just FutureGen

Roadmap RD&D Needs for Carbon Capture and Storage

- For both IGCC and pulverized coal systems
  - affordable CO_2 capture systems and simplified integration of CO_2 capture equipment
  - technologies to increase plant efficiency to reduce both the amount of coal used and CO_2 emitted
  - improvements in costs of CCS technology
- For IGCC
  - combustion turbines that burn hydrogen
- For CO_2 Sequestration
  - experience with what happens to CO_2 in saline reservoirs
  - solutions to long-term liability issues

Estimate of Federal and Private Sector Costs of Roadmap Through 2025 (in Billions US $)

Research & Development (80% Federal - 20% Industry)	$4.3
Demonstrations (50% Federal – 50% Industry)	$6.7
TOTAL COST of ROADMAP	$11.0
Total Industry Share	$4.1
Total Federal Share	$6.9

- Note that federal costs will be higher in the first five years of the roadmap when government R&D project cost sharing commitments are approximately 80% of total project costs.
- These costs only include the costs of NEW demonstrations, not currently supported by DOE. Thus, neither the Excelsior nor the Orlando IGCC projects costs are included.

Conclusions

- "Heroic" goals of Roadmap ARE ACHIEVABLE only if we act now
- Not just funding technology advancement

  This is a matter of US Energy Security and impact on our Standard of Living

- We must be strong advocates for LONG TERM Energy Policy thinking…

  and ACTION

ROADMAP BACKUP DOCUMENTS

The following pages provide more details about the technology needs of the various Roadmap program elements.

Innovations for Existing Plants

- Roadmap targets improvements in SO_2, NOx, Hg, PM, SO_3 in 2010 and 2015
- Coal-specific targets for Bituminous and Subbituminous coals
- Need for demonstrations of mercury control technologies to meet CAMR rules
- R&D improvements in fresh water use and by-product use needed

IGCC

- Continual improvements in capital cost, reliability, and air emissions.
- Key needs:
  - warm gas cleanup
  - improved materials of construction (reliability)
  - cheaper oxygen
  - advanced turbines and fuel cells
  - carbon capture

Advanced Combustion

- CURC recognizes that technologies applicable to combustion systems are dispersed throughout the budget
- Existing fleet of 300 GW in the US is combustion based; will need new technologies to address CO_2 capture if carbon requirements imposed
- Key needs
  - advanced materials for USC stress
  - low cost carbon capture technologies

Gas Turbines

- Goals include Hydrogen capability, higher efficiency, availability, and lower NOx
- Need resources for 2 alternative designs and oxy-water combustion concept (for CO_2 capture)
- Key research areas
  - H_2 turbine development
  - low NOx combustion
  - sensors/monitoring
  - improved materials

Carbon Management

- Capture program should be balanced between gasification and combustion systems
- Major issue: need for large long-term demonstrations of storage, versus competing $$ needs of earmarks, FutureGen. (3 storage demos could cost $160M plus $500M for the CO_2)
- Cost reduction opportunities are primarily in capture arena
- Research opportunities - possible co-disposal of other pollutants?

Fuel Cells

- CURC-EPRI generally on common ground with DOE program
- Major push to decrease costs and increase size

Fuels

- Key issue is DOE hydrogen focus vs. inclusion of FT liquids and chemicals
  - Sub-theme: Are liquids/chemicals an R&D challenge or a deployment challenge?
- CURC members advocate the broader vision, but focus remains on power generation.

Existing Plants Roadmap Performance Targets

Innovations for Existing Plants	2005	2010	2015
Emissions			
SO_2, % removal (emissions, lb/MM Btu)	90-95 (0.22 - 0.04)	98 (0.09 – 0.009)	99 (0.04 - .01)
NOx, lb/MM Btu (SCR equipped)	0.04 - 0.08	0.02 - 0.04	0.01 - 0.02
NOx, lb/MM Btu (comb. cntls.)	0.1 - 0.3	0.06 - 0.1	<0.05 - 0.1
Hg removal, %	co-benefits 30 - 90%	65 - 90	80 - 95
PM emissions, lb/MM Btu	0.03 - 0.1	0.01 - 0.02	0.01
SO_3 emissions, ppmv	50 - </=2	10 - </=2	</=2
CO_2 Capture	See advanced technology roadmap for CO_2 capture goals		
Heat-rate improvement, Btu/kWh (HHV)	baseline	baseline	baseline
Fresh water use, % reduction	baseline	5 - 10	25
By-product Utilization, %	39	50	75
Total R&D and Demonstration costs, $ Million		580	580

Note that the targets are dependent on the coal type being used and that the data represent targets for both bituminous and sub bituminous coals

Programmatic Federal and Private Sector Costs of Roadmap (in Millions US $)

	IGCC	Combustion	IEP	Sequestration (Storage)	Fuel Cells	Turbines	TOTALS
R&D	$2,150	$375	$360	$225	$730	$450	$4,290
Demos	$3,050	$2,040	$800	$160	$475	$180	$6,705
Industry Share	$1,955	$1,095	$470	Costs borne by federal government	$385	$180	$4,085
Federal Share	$3,245	$1,320	$690	$385	$820	$450	$6,910
TOTALS	$5,200	$2,415	$1,160	$385	$1,205	$630	$10,995

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Recent Experience with SCR Catalyst For PRB Fuels, High Sulfur Fuels, And Low Dust Applications

By

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ABSTRACT

Hitachi has supplied SCR catalyst for several utilities in the United States that have recently commissioned the SCRs including AES Somerset, CP&L Roxboro #4 and KCP&L Hawthorn. The Somerset and Roxboro #4 plants burn bituminous coal while Hawthorn burns sub-bituminous (Powder River Basin Coal). The Somerset SCR and Hawthorn SCR are in a high dust configuration while the Roxboro #4 SCR is installed in a low dust configuration. This paper describes the catalyst design basis, NOx removal performance, pressure drop, ammonia slip and SO2 to SO3 oxidation as well as the performance of the on-line clean equipment to maintain catalyst cleanliness. Experience with both sootblowers and acoustic horns are described.

INTRODUCTION

Three diverse coal fired boilers with Hitachi plate type SCR catalyst are on line. Each represents a distinct challenge as one is a high dust configuration in a boiler firing medium to high sulfur eastern bituminous coal with sootblowers, the other in a boiler firing low sulfur Appalachian bituminous coal in a low dust configuration with cleaning from acoustic horns and the third a high dust configuration firing sub-bituminous Powder River Basin coal with a SCR that is also cleaned with acoustic horns. The designs are briefly discussed and the operation results to date, including the impact of cleaning method, are discussed.

In addition, new developments are addressed. The first is the ability of SCR catalyst to withstand the rigors of the SCR catalyst rejuvenation processes being introduced are discussed with emphasis on strength, cleaning ability, and overall life. Second, is the development of a very low SO_2 to SO_3 oxidation Hitachi catalyst. Its strengths and weaknesses are described.

Hitachi is uniquely suited to address different boiler configurations firing a wide variety of fuels. Figure 1 shows some of these including coal, petroleum products, Orimulsion gas, biological based fuels, and gases of all descriptions. These are fired in pulverized coal and cyclone boilers, both wet and dry bottom; in combustion turbines; process boilers and heaters; furnaces; coke ovens; pickling plants; municipal solid waste, and other incinerators and diesel engines. In refineries Hitachi experience includes reformers, process boilers and heaters, crude heaters plus fluidized catalytic crackers.

HIGH DUST – HIGH SULFUR

The Somerset station boiler owned by AES has been on line originally during ozone seasons but currently continuously with an operational SCR since July of 1999.

SCR DESIGN CONDITIONS

The SCR is installed in a high dust configuration, directly after the economizer on this pulverized coal

fired unit. Both an economizer and an SCR bypass are provided. The boiler fires a medium to high sulfur eastern bituminous coal in a high dust configuration. The layout is shown in Figure 2 as a photograph and in Figure 3 as a schematic. Catalyst cleaning is affected by means of sootblowers. The SCR catalyst design parameters are given in Table 1.

Size	675 MW
Fuel	Bituminous Coal
Configuration	High Dust
Operation	Continuous
Comm'l.. Operation	July 1999
Gas Flow	6,500,000 lb/hr
Gas Temperature	649 ^{0}F
Inlet NOx	340 ppm
O_2	3%
H_2O	7%
SO_2	1140-3490 ppm
Dust	5 gr/dscf
Outlet NOx	34 ppm
DeNOx Eff.	90%
NH_3 Slip	3 ppm
Catalyst Vol.	897 m^3
Gas Velocity	6.0 m/s
SO_2 Oxidation	< 0.75%
Pressure Drop	2.8 "WG
Catalyst Life	24,000 hr

Table 1: Somerset SCR Design Parameters

The design fuel coal is given in Table 2 below. The average sulfur content is over 2% with the maximum being a little more than 4%. The maximum Hitachi experience is with 5% sulfur petroleum coke. In addition, the arsenic impact could be somewhat high if the maximum arsenic coincides with the minimum calcium oxide level.

	Units	Ave.	Max.	Min.
Heat	BTU/lb	13023	13237	12550
Moist.	%	5.87	6.18	5.53
Vol.	%	37.05	40.09	35.60
FC	%	49.49	52.03	44.79
Ash	%	7.88	9.15	6.67
S	%	2.41	4.12	1.41
C	%	71.90	74.36	68.41
H	%	4.90	5.21	4.69
N	%	1.31	1.53	1.14
O	%	6.47	7.20	5.63
Cl	%	0.12	0.14	0.07
SiO_2	%	46.44	51.30	42.81
Al_2O_3	%	22.31	26.18	19.28
Fe_2O_3	%	18.26	28.79	12.60
TiO_2	%	0.96	1.17	0.87
P_2O_5	%	0.28	0.44	0.04
CaO	%	4.20	5.92	2.61
MgO	%	0.84	0.98	0.67
Na_2O	%	0.53	0.70	0.42
K_2O	%	1.37	1.49	1.20
SO_3	%	4.96	7.18	3.05
As	PPM	4.44	6.73	2.77
Ba	PPM	5.93	10.95	0.20
Mn	PPM	15.59	21.05	10.92

Table 2: Somerset Coal Analysis

OPERATION

The SCR has been on line since July 1999. To date it has performed better than expected meeting the DeNOx efficiency, slip and SO_2 oxidation rate while having a MCR catalyst pressure drop of 1.4 in. W.G. The SCR cleanliness has been better than expected. The steam sootblower operating frequency has been reduced to once

per week. The catalyst has remained very clean as shown in Figures 4 and 5; with no dust buildup or erosion being observed and with the only ash buildup being found on horizontal surfaces within the reactor but not on in the catalyst. Throughout operation the pressure drop across the catalyst has remained constant: further evidence of a clean catalyst bundle.

The catalyst is performing better than expected. The activity is higher than originally planned. This has been established by testing sample catalyst coupons at regular intervals. The results of these activity tests are given in Figure 6 along with the initial catalyst activity design curve for comparison. It has been known that the sample coupons are subject to inlet turbulent flow that causes their test results to be conservative, showing higher deterioration than the average of the SCR bed catalyst. To better understand the actual bed conditions, two (2) catalyst plate elements were removed from the bed and tested along their length. The average of these tests results is also shown in Figure 6.

LOW DUST - LOW SULFUR

The Roxboro 4 unit owned by Carolina Power and Light has been on line during ozone seasons with an operational SCR since July of 2001. It consists of two (2) boilers feeding one turbine/generator.

SCR DESIGN CONDITION

The SCR is installed in a low dust configuration, directly after the hot electrostatic precipitator on each of these pulverized coal fired boilers. They fire low sulfur southern Appalachian bituminous coal.

The east side of the east boiler is shown in Figure 7. The flue gas exits the hot electrostatic precipitator flowing north to the rear of the boiler. The ammonia injection grid is seen in the picture. From there it turns upward and then to the west where it enters the reactor, flowing downward through the catalyst. A schematic of the reactor is shown in Figure 8. The SCR catalyst design parameters are given in Table 3.

Size	735/2 MW
Fuel	Bituminous Coal
Configuration	Low Dust
Operation	Ozone Season
Comm'l.. Operation	July 2001
Gas Flow	1,725,300 SCFM
Gas Temperature	735 ^{0}F
Inlet NOx	278 ppm
O_2	3¼%
H_2O	6½%
SO_2	1140-3490 ppm
Dust	100 mg/Nm^3
Outlet NOx	58.5 ppm
DeNOx Eff.	79%
NH_3 Slip	2 ppm
Catalyst Vol.	314 m^3
Gas Velocity	6.0 m/s
SO_2 Oxidation	< 1.0%
Pressure Drop	1.3 "WG
Catalyst Life	24,000 hr

Table 3: Roxboro 4 SCR Design Parameters

The design fuel coal is given in Table 4. The sulfur content is 1.5 % or less. In addition, the maximum arsenic level is high compared to the minimum calcium oxide level. The catalyst design had to account for the potential arsenic deactivation of the catalyst over its life.

	Units	Max.	Min.
Heat	BTU/lb	13500	10500
Moist.	%	11.0	3.0
Vol.	%	39	28
FC	%	55	45
Ash	%	17	5
S	%	1.5	0.4
C	%	80	60
H	%	6	4
N	%	1.7	1.0
O	%	8	2
Cl	%	0.1	0.01
SiO_2	%	70	10
Al_2O_3	%	38	8
Fe_2O_3	%	25	2
TiO_2	%	3.5	0.4
P_2O_5	%	0.6	0.1
CaO	%	10	0.5
MgO	%	8	0.3
Na_2O	%	4.0	0.1
K_2O	%	3.0	0.1
SO_3	%	10	0.1
As	PPM	12	0
Ba	PPM	3	0
Mn	PPM	78	0

Table 4: Roxboro 4 Coal Analysis

Acoustic horns are used for catalyst cleaning. Actually, it is Hitachi's experience that low dust catalyst is more difficult to clean than that from high dust. Although the volumetric flow rate is lower the particulate is much smaller. This increases the pluggage potential of the catalyst pores masking the catalyst reaction sites. The acoustic horn arrangement is shown in Figure 9.

OPERATION

To date no plugging has been experienced as evidenced in Figure 10 showing the actual catalyst inlet. Preliminary SO_2 oxidation testing indicates that the 1% limit has easily been achieved as the average for both SCR reactors is 0.73%. For the new catalyst the ammonia slip values measured were well below the requirements.

SUB-BITUMINOUS COAL (PRB)

The Hawthorn 5 unit owned by Kansas City Power & Light has been on line in continuous operation with an operational SCR since May of 2001.

SCR DESIGN CONDITION

The SCR is installed in a high dust configuration, directly after the economizer of this pulverized coal fired boiler. It fires low sulfur sub-bituminous Powder River Basin coal.

A schematic of the reactor is shown in Figure 11. It also has an economizer and an SCR bypass. The SCR catalyst design parameters are given in Table 5.

Size	500 MW
Fuel	Sub-Bit. (PRB)
Configuration	High Dust
Operation	Continuous
Comm'l.. Operation	May 2001
Gas Flow	5,595,000 SCFM
Gas Temperature	695 ^{0}F

Inlet NOx	135 ppm
O_2	3½ %
H_2O	13.6 %
SO_2	420 ppm
Dust	32,710 mg/Nm^3
Outlet NOx	59.2 ppm
DeNOx Eff.	55.6 %
NH_3 Slip	2 ppm
Catalyst Vol.	477 m^3
Gas Velocity	5.7 m/s
SO_2 Oxidation	< 0.75%
Pressure Drop	2.0 "WG
Catalyst Life	24,000 hr

Table 5: Hawthorn 5 SCR Design Parameters

The design fuel coal is given in Table 6. The sulfur content is very low. In addition, there is no significant arsenic. The calcium oxide level is extremely high and the concern is catalyst porosity masking by the CaO that shortly becomes $CaSO_4$. The catalyst design had to account for the potential $CaSO_4$ masking of the reaction sites with its potential catalyst deactivation over the catalyst life.

	Units	Ave.	Max.	Min.
Heat	BTU/lb	8350	8100	8600
Moist.	%	30.6	29.0	32.2
Vol.	%	31.1	28.8	33.4
FC	%	32.8	30.5	35.9
Ash	%	5.5	4.6	6.4
S	%	0.33	0.23	0.43
C	%	48.0	46.3	49.6
H	%	3.4	3.1	3.7
N	%	0.7	0.6	0.8
O	%	11.5	-	-
Cl	%	0.01	0.0	0.02
SiO_2	%	33.0	27.9	38.1
Al_2O_3	%	15.5	13.2	17.8
Fe_2O_3	%	6.0	3.6	8.4
TiO_2	%	1.3	0.8	1.8
P_2O_5	%	1.7	1.0	2.4
CaO	%	22.5	17.6	27.4
MgO	%	4.0	1.7	6.3
Na_2O	%	1.4	0.4	2.4
K_2O	%	0.3	0.0	0.6
SO_3	%	13.0	10.1	25.9
As	PPM	-	-	-
Ba	PPM	-	-	-
Mn	PPM	-	-	-

Table 6: Hawthorn 5 Coal Analysis

OPERATION

Hawthorn Unit 5 is a pulverized coal fired boiler with a high dust SCR. Thus we expect high dust loadings in the reactor. Four (4) acoustic horns per catalyst layer are used for cleaning, the arrangement being shown in Figure 13. Note the clean environment and the condition of the catalyst surface. No increase in pressure drop through the catalyst bundle has been observed. Tuning of the SCR was still in progress as this paper is being written. Preliminary data supports the conclusion that all the SCR catalyst performance requirements are being met.

NEW DEVELOPMENTS

Rejuvenation:

The industry is delving deeply into SCR catalyst rejuvenation as a potential operating cost saving method for catalyst replenishment. The key to catalyst longevity with these wet rejuvenation processes is the mechanical stability of the original catalyst that is to be rejuvenated. The Hitachi plate

catalyst with its stainless steel mesh core is the most mechanically stable, study and rugged catalyst on the market. Its advantages are:

- It has the maximum mechanical strength of all the catalysts for handling.
- Its core strength is not weakened by moisture, as is ceramic or paper based material. Thus it lasts longer through rejuvenation processes.
- It is the least susceptible to damage during rejuvenation.
- For damaged catalyst single plate replacement is possible rather than being limited to large sections.
- Hitachi plate catalyst may be dismantled to the elemental state either locally or in its entirety to completely remove any dust or ash as illustrated in Figure 13.

SO_2 Oxidation

Hitachi offered 3 coal-fired catalysts, C1, C2, C3, for high dust loadings. These catalyst types had increasing activity with increasing SO_2 to SO_3 oxidation rates. These rates all varied in a similar fashion with temperature; the higher the temperature the higher the oxidation rate. Now Hitachi is offering a fourth catalyst type, C0, that offers very high activity with very low oxidation for relatively high temperature service. This is illustrated in Table 7.

	Relative Volume/Oxydation			
Temp.	C3	C2	C1	Co
700 F	V_1	$V_1 + \alpha$	$V_1 + \beta$	$V_1 + \gamma$
	1.2 %	1.0 %	0.6 %	0.5 %
750 F	-	-	V_2	$V_2 - \delta$
	-	-	1.0	0.5
780 F	-	-	V_3	$V_3 - \varepsilon$
	-	-	1.4 %	0.5 %
Where $\alpha < \beta < \gamma$ and $\delta < \varepsilon$				

Table 7: Low Oxidation Catalyst

This catalyst offers considerable advantages over the catalyst currently being offered. However, the activity of this new catalyst drops off rapidly at lower temperatures. Thus this catalyst may not be appropriate for boilers operated with large load swings. For base loaded units operated at or near full load this catalyst might be used to considerable advantage by minimizing the potential for ammonium bisulfate formation in down stream equipment and a blue plume at the stack.

CONCLUSIONS

The versatility of the plate type catalyst is continually being demonstrated through it many diversified applications. New developments in catalyst formulations for the plate catalyst further expand its usefulness. Its rugged metallic core and elemental building block construction make it the most amenable catalyst for the wet rejuvenation processes being offered today, giving the plate catalyst the maximum overall useful life.

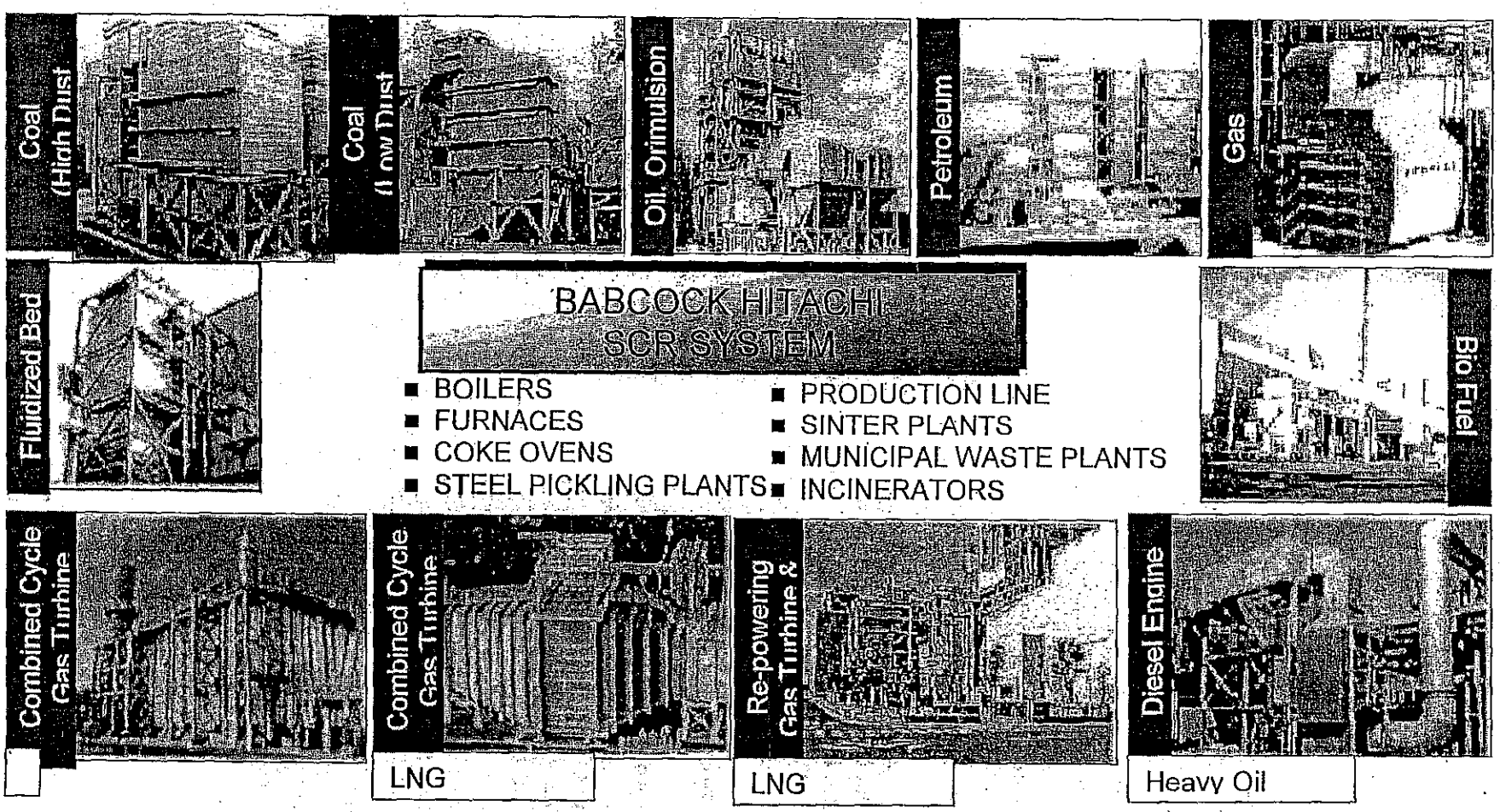


Figure 1: SCR Applications and Experience

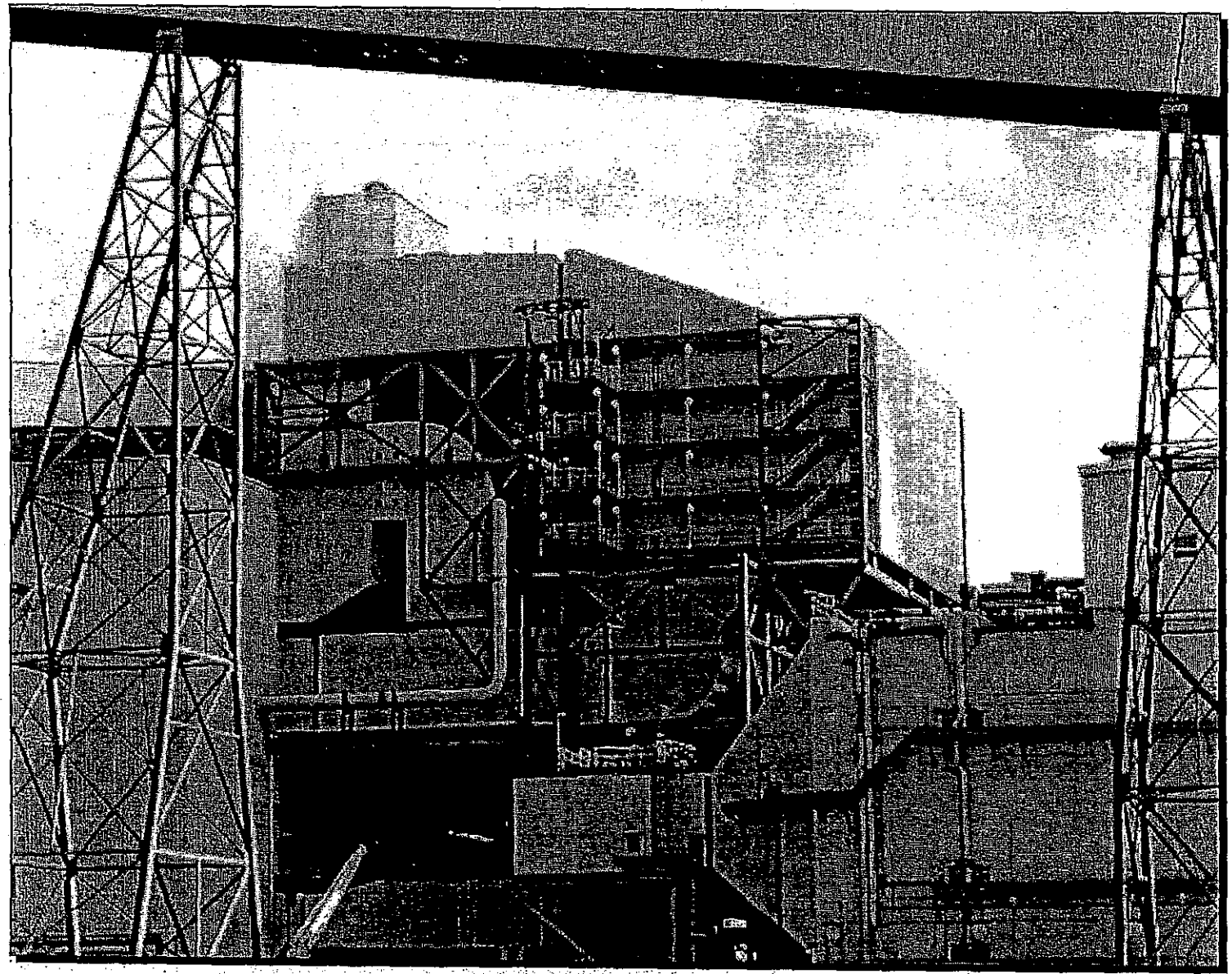


Figure 2: AES Somerset – 675 MW SCR

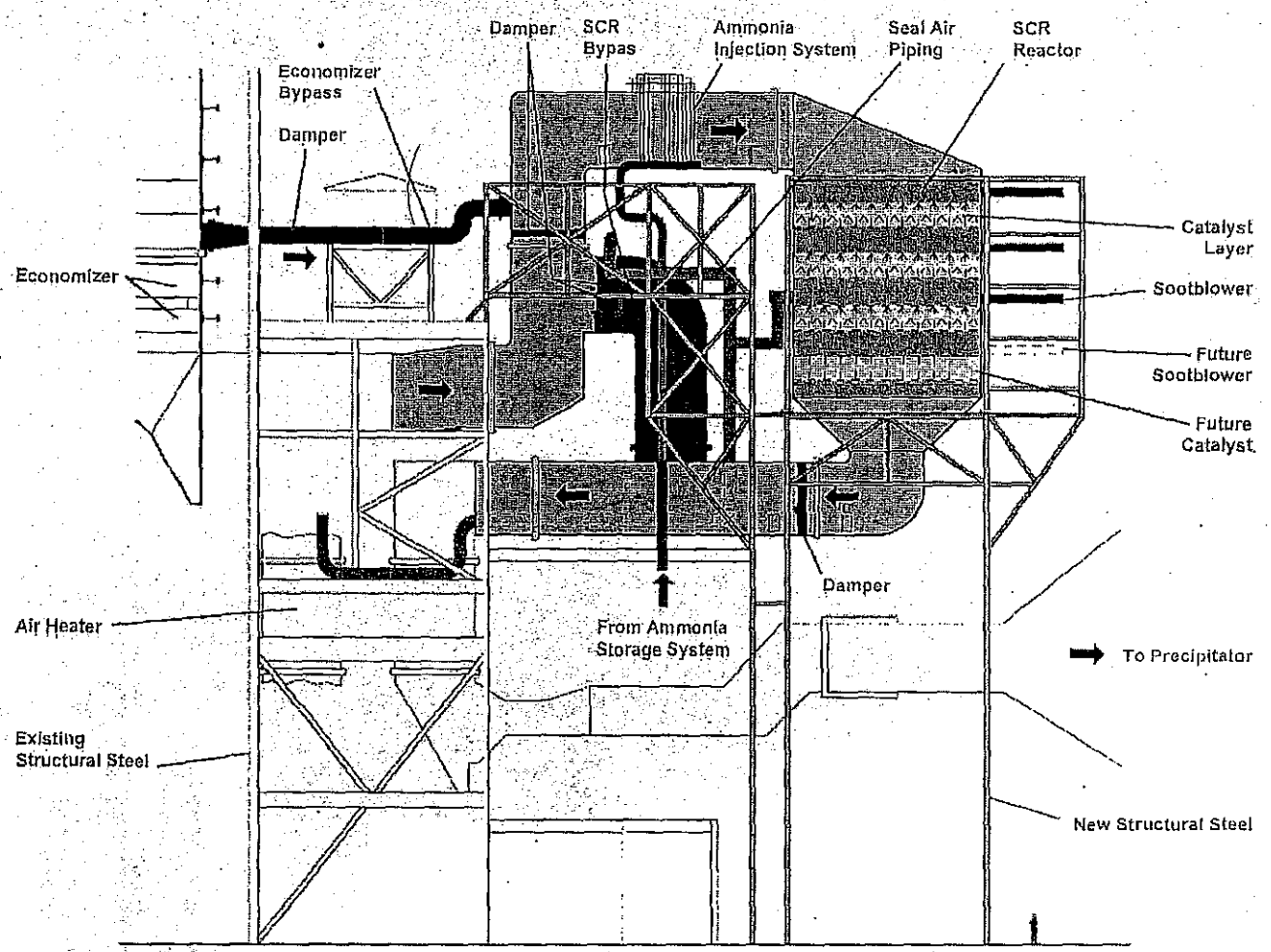


Figure 3: AES Somerset - 675 MW SCR System

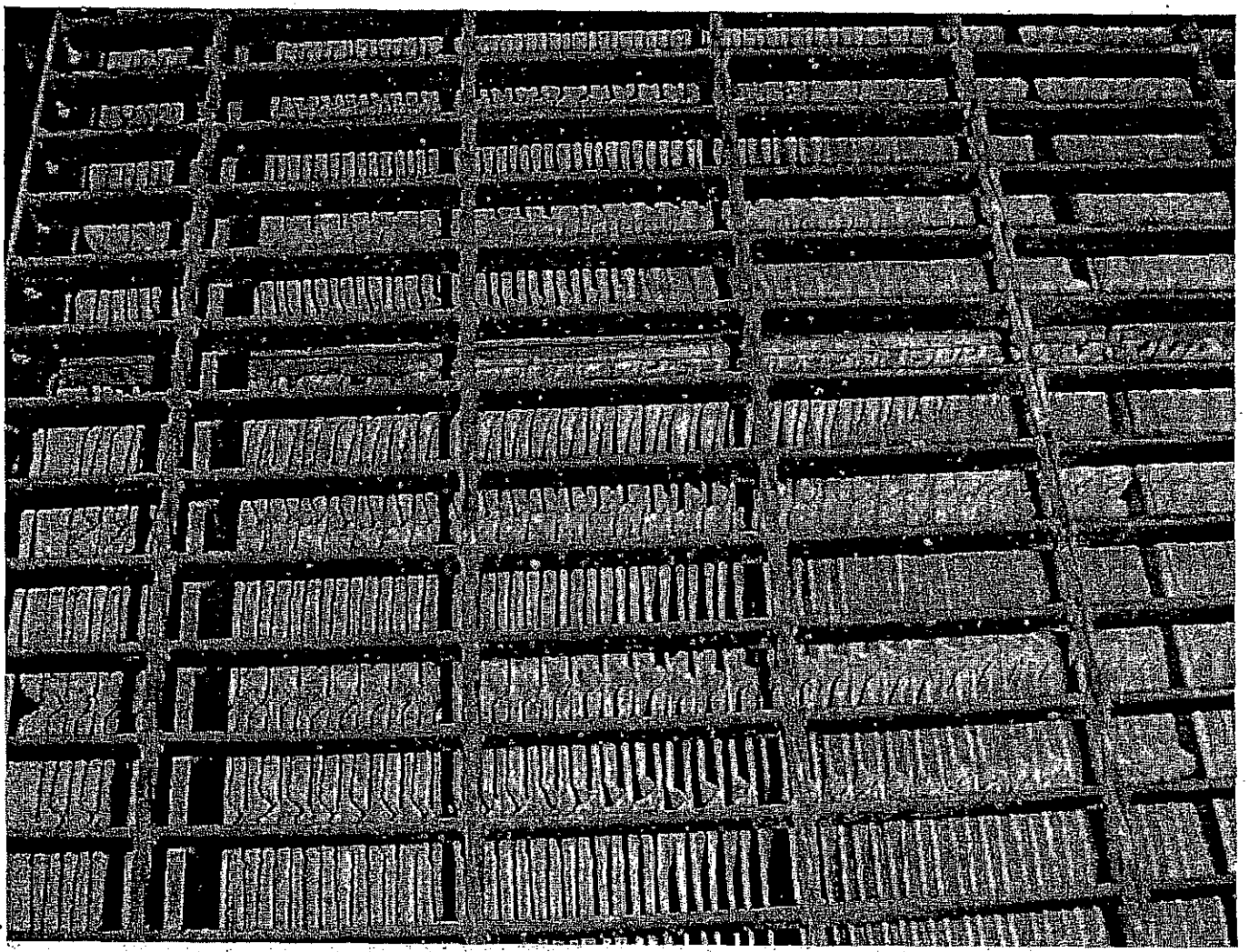


Figure 4: AES Somerset Catalyst After Two Ozone Seasons

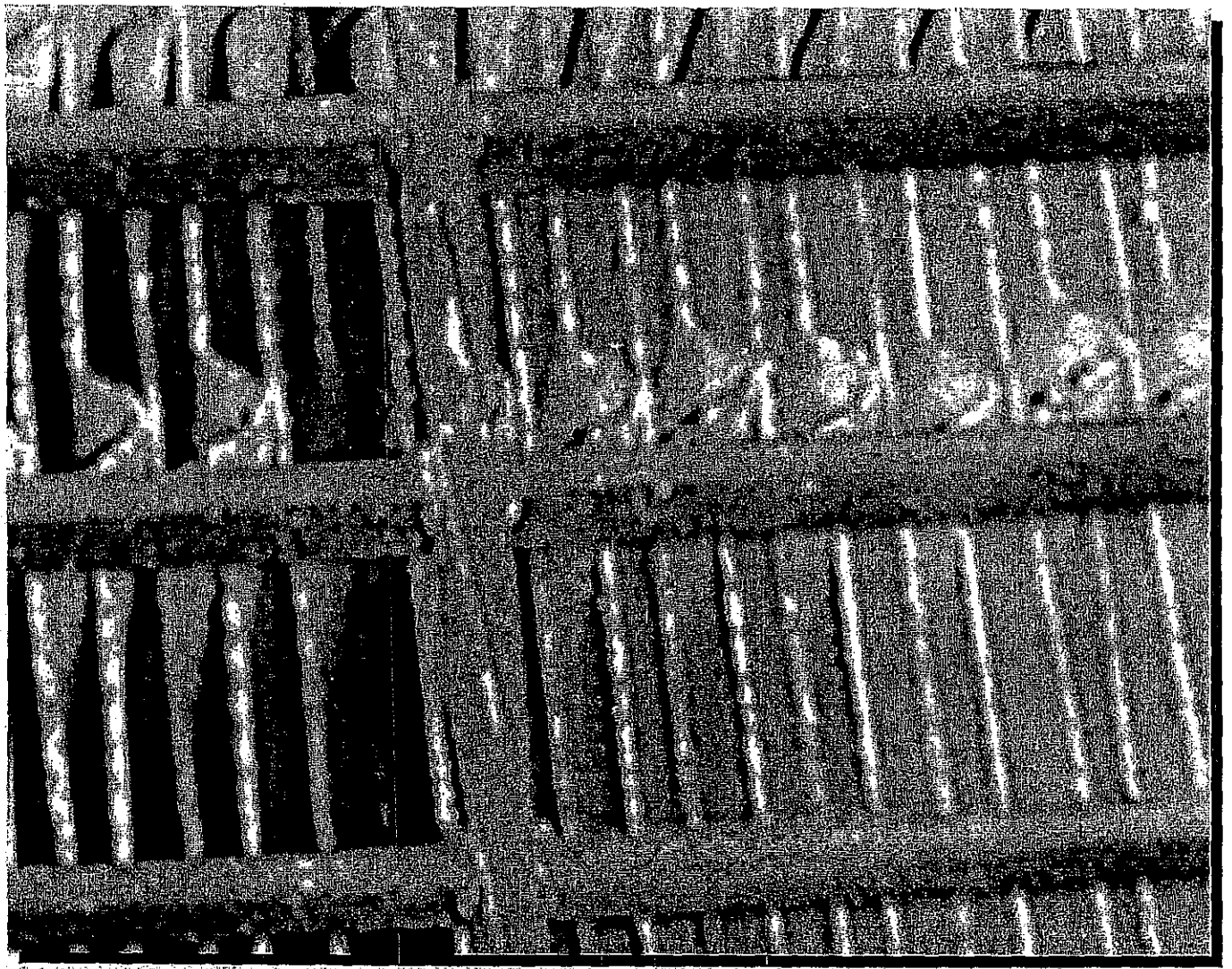


Figure 5: AES Somerset Catalyst After Two Ozone Seasons

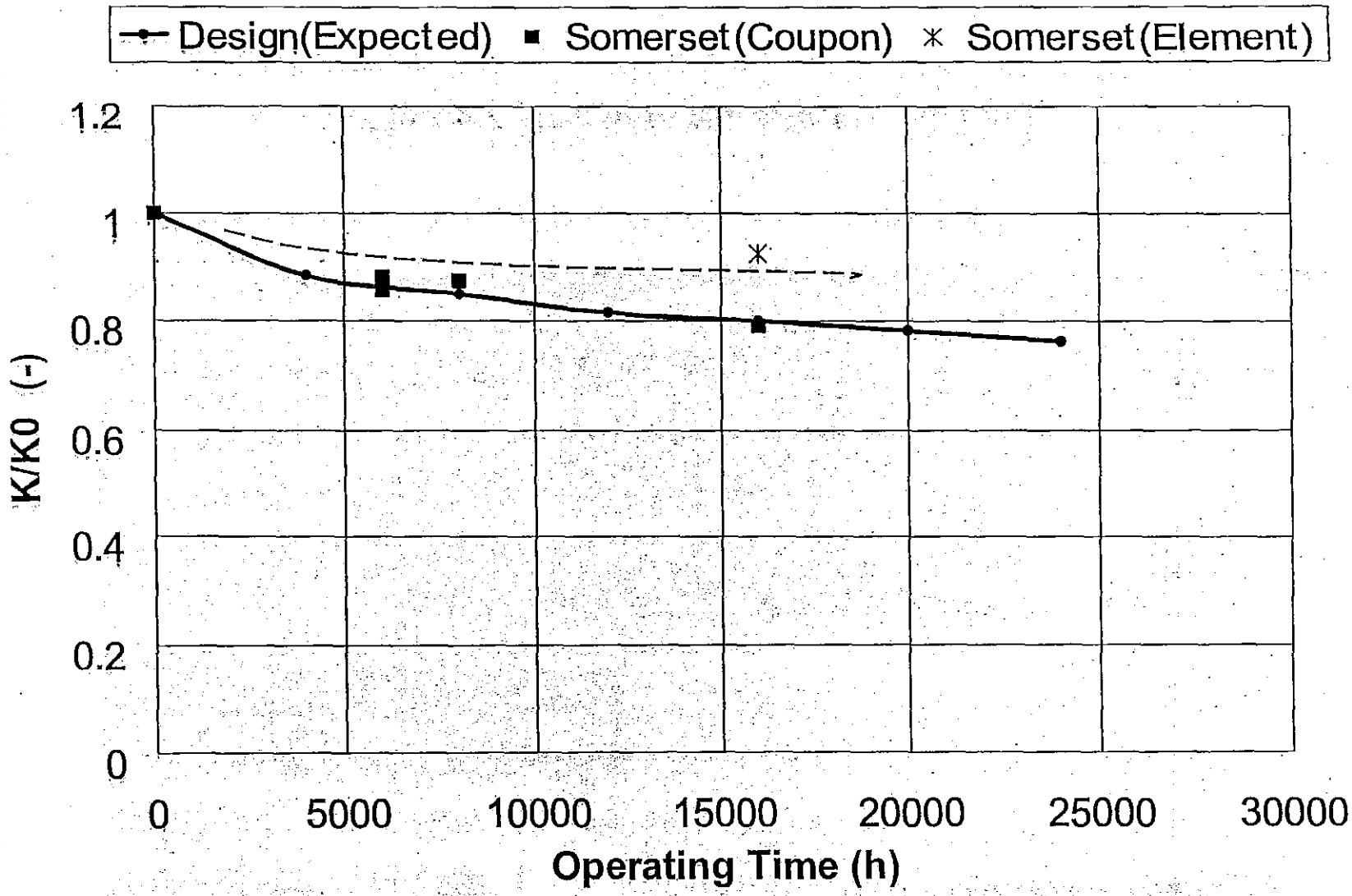


Figure 6: Somerset Catalyst Deactivation

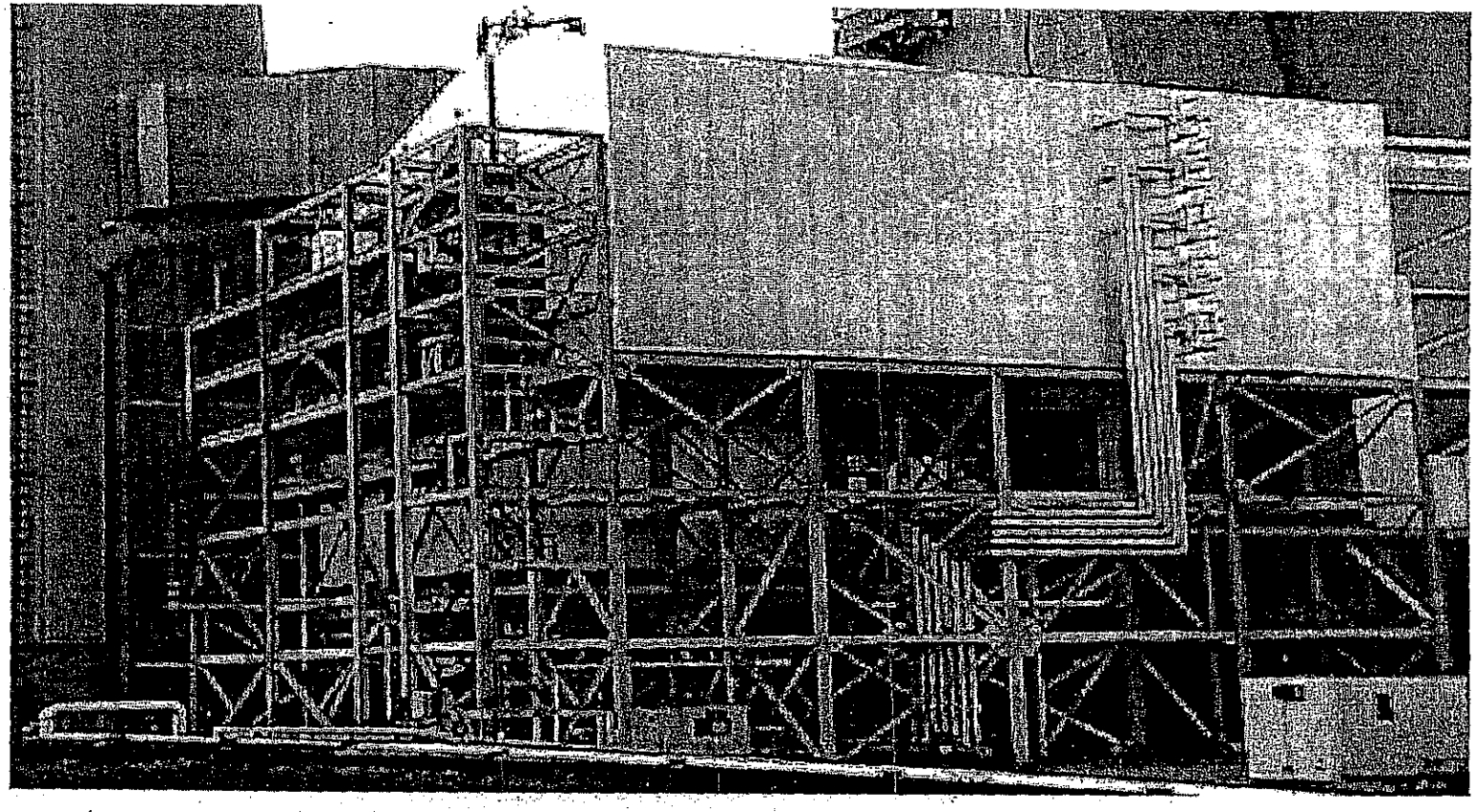


Figure 7: Roxboro No. 4 SCR – East Side

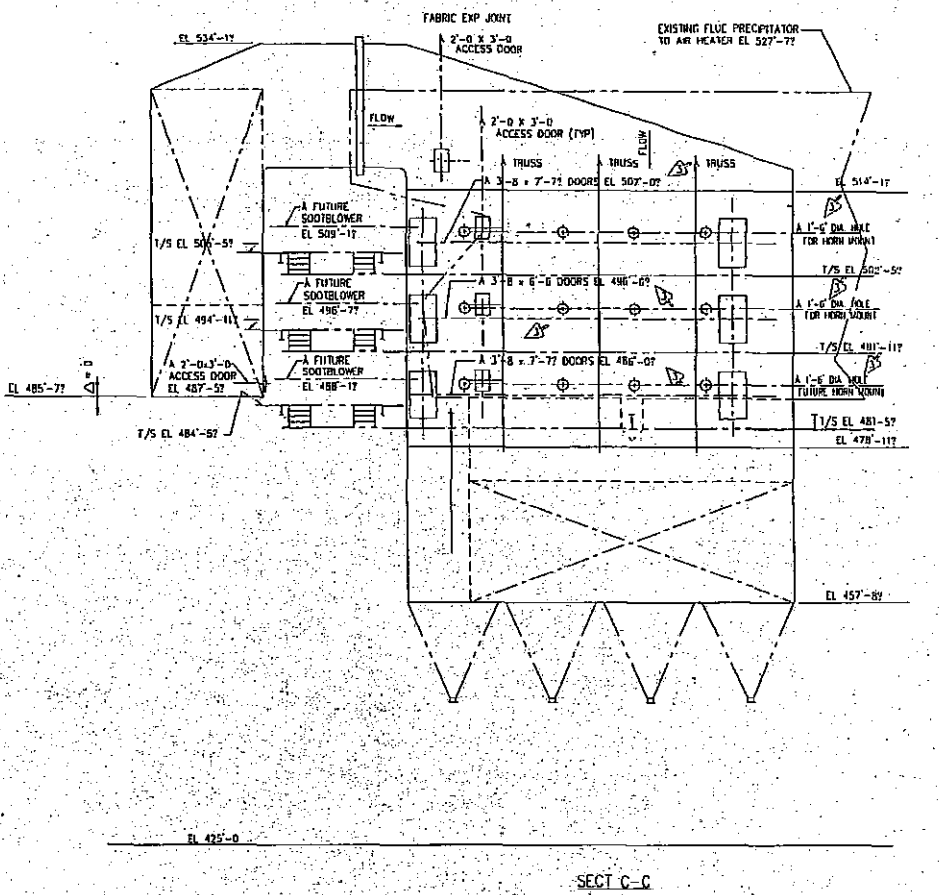


Figure 8: Roxboro No. 4 Reactor Schematic

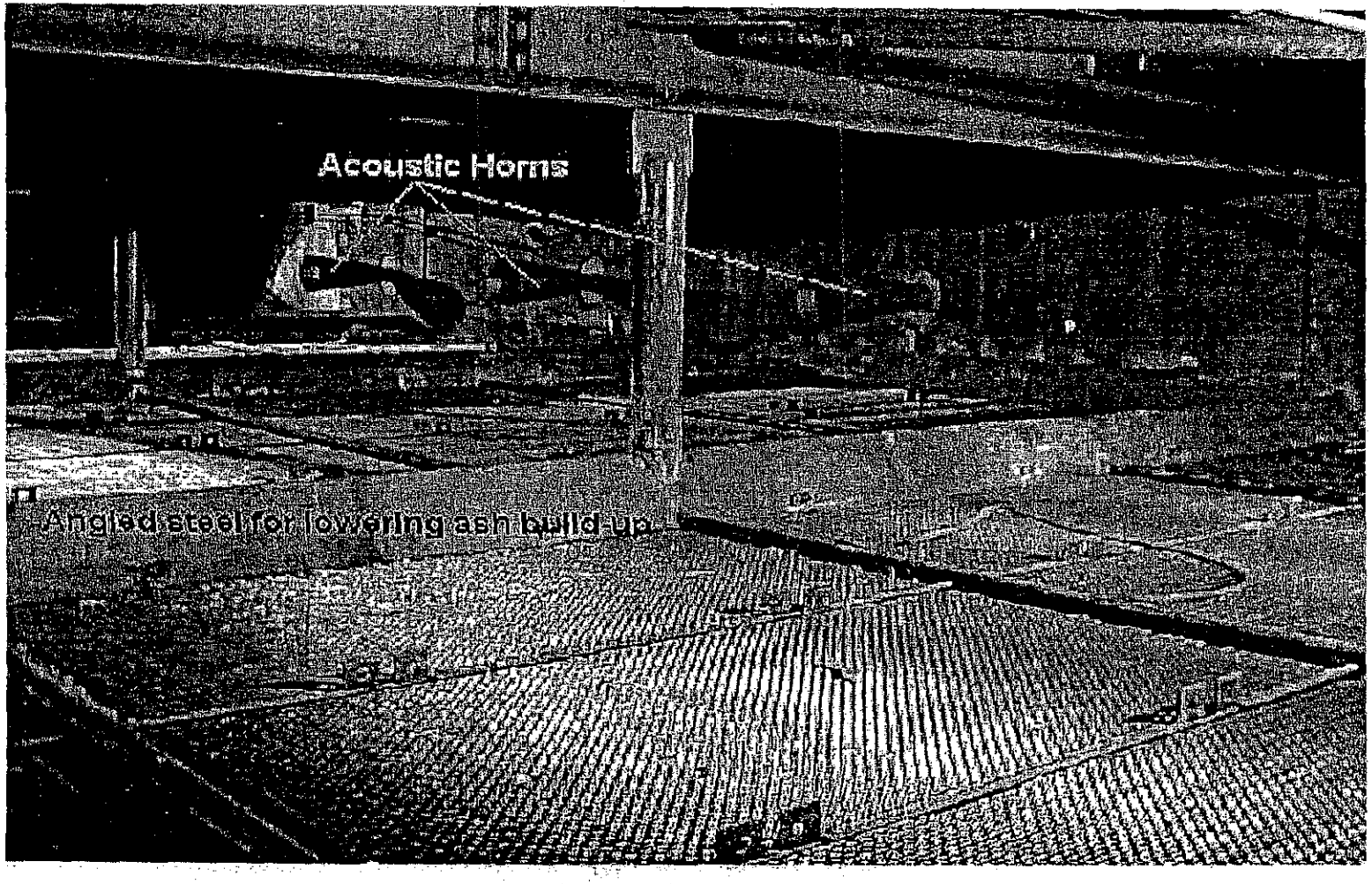


Figure 9: Roxboro No. 4 Acoustic Horns

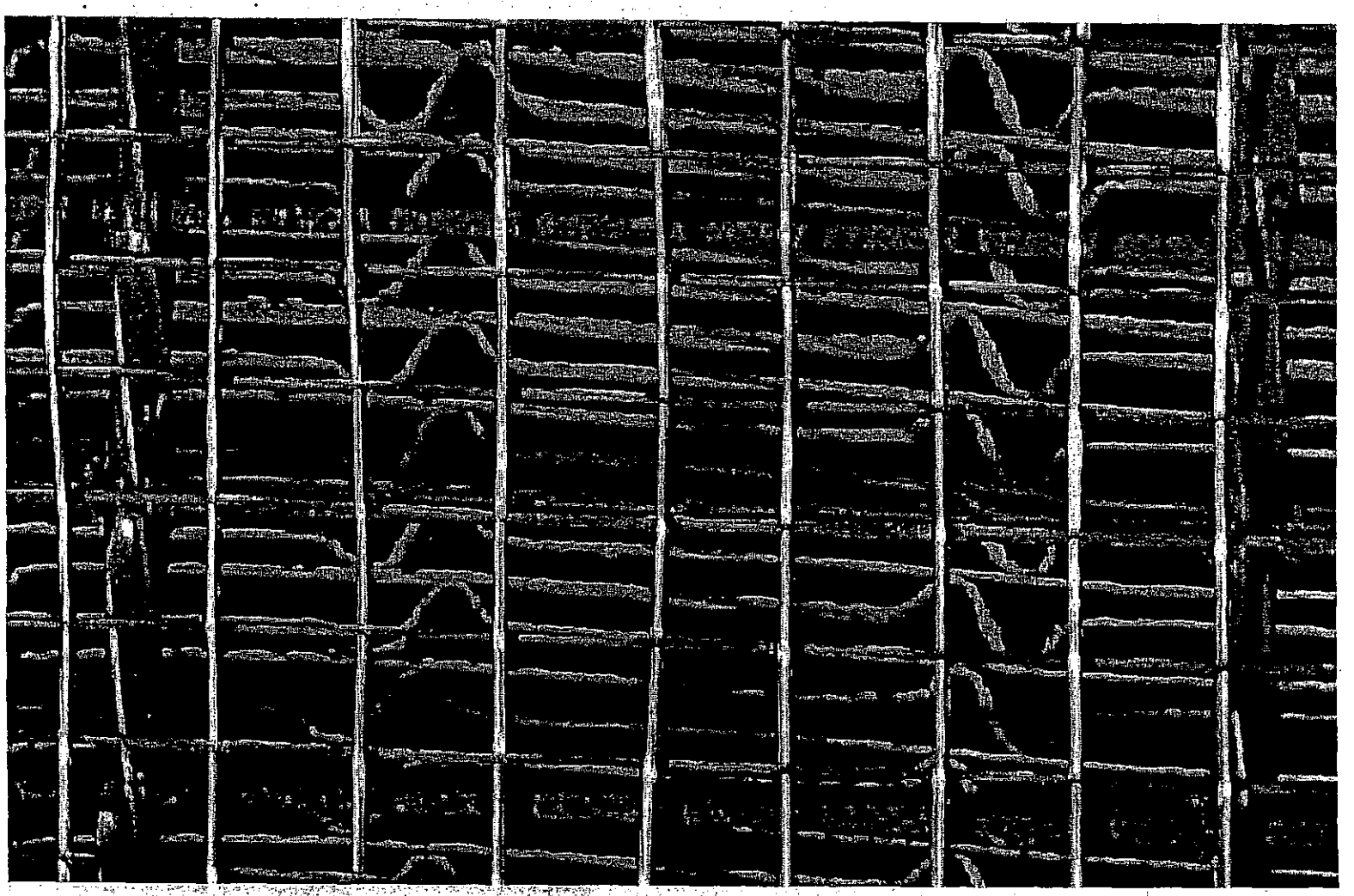
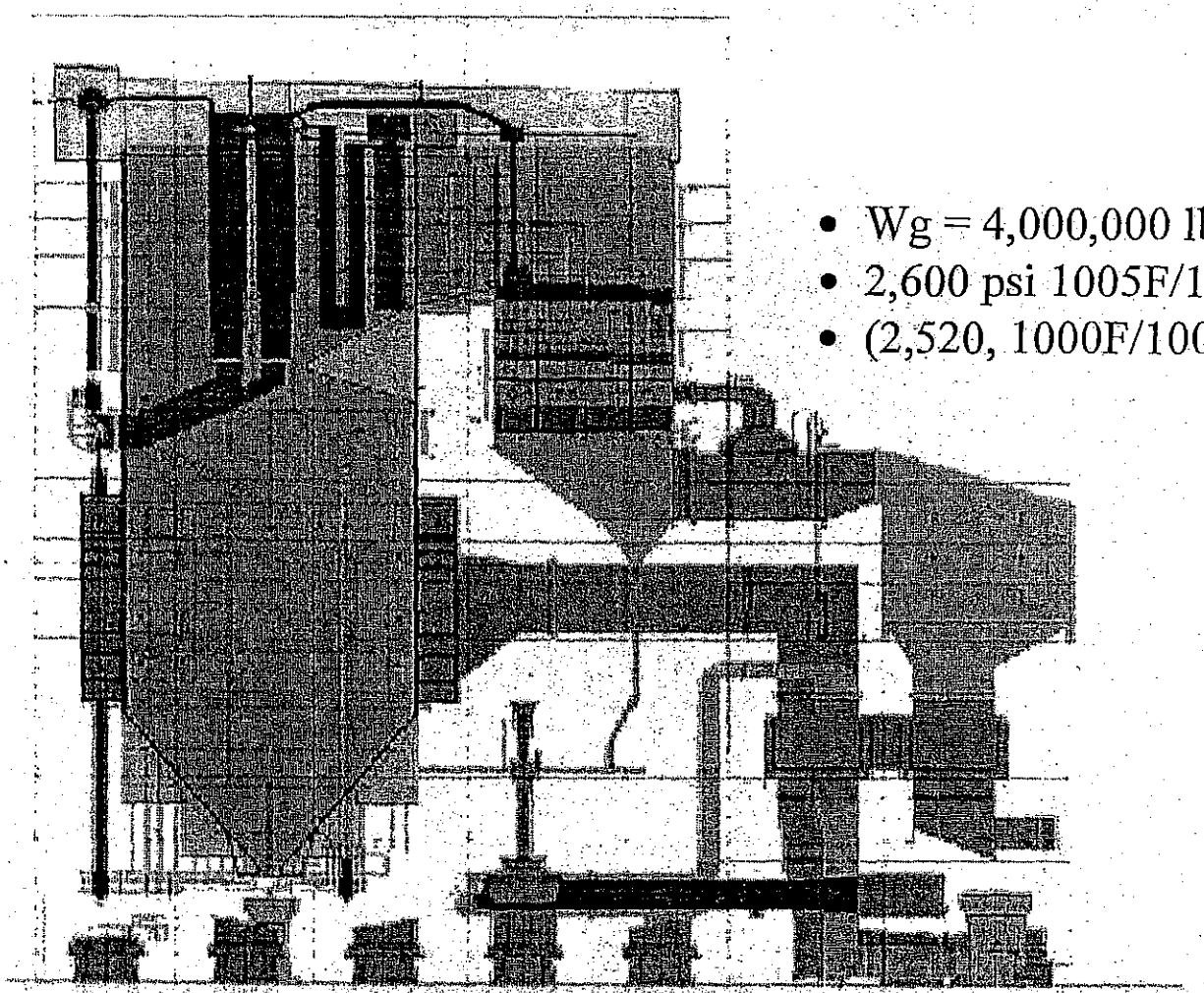


Figure 10: Roxboro No. 4 Hitachi Catalyst



- Wg = 4,000,000 lb/hr
- 2,600 psi 1005F/1005F
- (2,520, 1000F/1000F @ Turbine)

Figure 11: Hawthorn Unit 5 Side Elevation

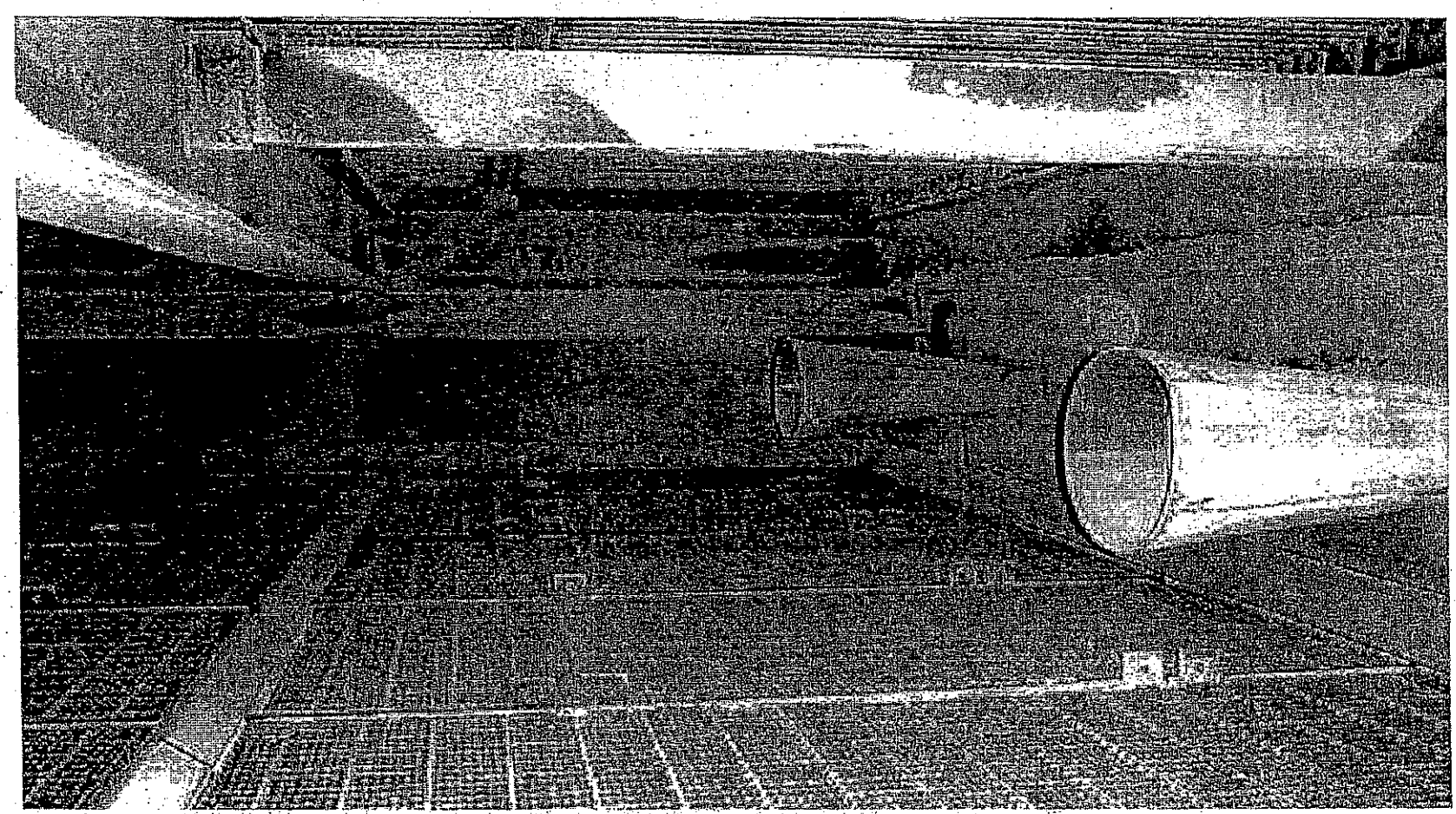
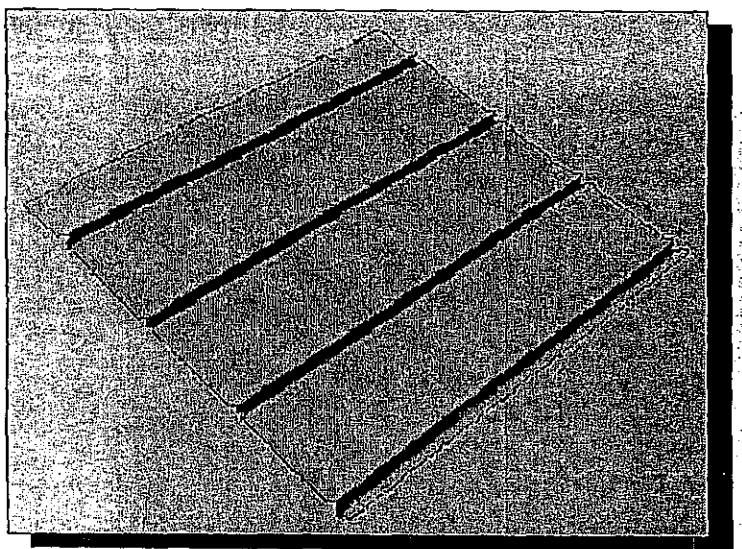
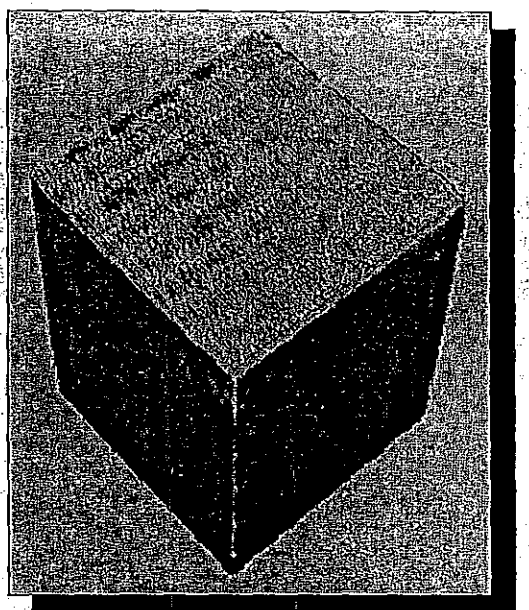


Figure 12: Hawthorn Unit 5 Acoustic Horns



CATALYST ELEMENT
[Thickness: Approx. 0.9mm]



CATALYST UNIT
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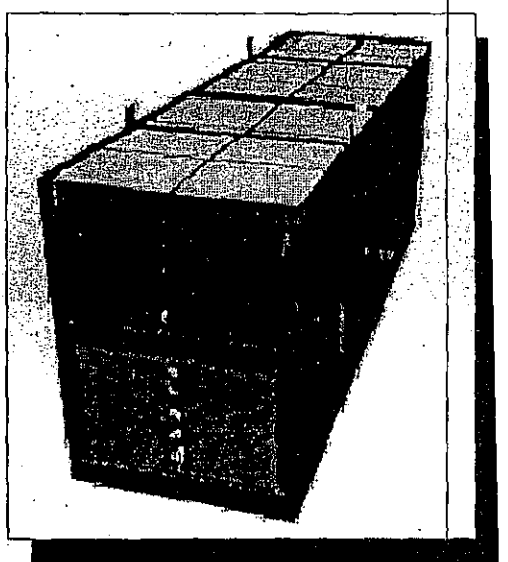

CATALYST
BLOCK/MODULE

Figure 13: Hitachi Catalyst Building Blocks

Selective Catalytic Reduction System Performance and Reliability Review

The 2006 MEGA Symposium, Paper # 121

By
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ABSTRACT

Using the 2005 U.S. Environmental Protection Agency's Electronic Data Reporting (EDR) site (www.epa.gov/airmarkets/emissions/raw/index.html) database of utility stack emissions, a review of installed SCR system NO_x removal performance and reliability has been undertaken. The NO_x emissions for all plants have been determined based upon hourly emissions and gross heat input to determine the plants overall NO_x removal efficiency and average outlet NO_x for the 2005 Ozone season. The data analysis was performed for all operating hours, including low load and startup conditions. Analysis of the data showed that removal efficiencies of 90% and greater were obtained by greater than 30 units and that overall Ozone season average NOx emissions rates of less than 0.05 lb/MMBtu were consistently achievable by SCR systems. The data also looks at the type of fuel and ammonia systems and their effect on the SCR system's ability to meet high levels of reliability. Last the ability for plant with long term (greater than 3 years) of operating to improve their process is review for three selected plants.

The review concludes that low NOx emissions rates can be achieved with very low hourly standard deviations. Further the data suggests that not all units with low emissions rate can obtain low standard deviations. The reason for this are investigated as related to boiler and SCR characteristics and system operation.

BACKGROUND

US SCR installations are unique from those of other countries in that the removal efficiencies of the systems are generally higher than in Europe or Japan. US installations also have been installed with full SCR bypass system allowing for the isolation of the system during non-Ozone season operation. These differences are largely due to the US regulatory system of trading NO_x emissions that makes it economically preferable to achieve higher removal efficiencies and operate only during the Ozone season. Unit emission rate caps as practiced in Europe, on the other hand, do not create the same incentive for higher NO_x removal efficiencies.

Previous work examined the reliability of SCR systems on US coal-fired electric utility plants in achieving high NO_x removal efficiencies, however a limit number of operational units were available. As more units have come on line and more data has become available, it is now possible to look at a fairly large population of units and find what trends are apparent and what lessons can be

learned. For some units, multiple years of data available allowing for an investigation of a plant ability to improve and maintain SCR performance.

For example, in Cichanowicz[1] and others examined data on twelve units that raised some questions regarding SCR reliability and ability to achieve 90% removal. In 2004, Staudt[2] and others reported on the results of surveys taken of users regarding their views on the reliability of SCR and FGD systems for high removal efficiency. In this effort, all of those companies operating SCR's installed in response to the NOx SIP Call that did respond indicated that overall reliability met or exceeded expectations. They also indicated that full load removal efficiencies were, on average 88%-89%, close to the guarantee levels of roughly 90%. However, the survey showed that the user's estimate of the best removal rate they thought the SCR system could achieve on a regular basis if they had a reason to operate it at higher removal rates was generally greater than 90% - and in every case greater than the guaranteed NO_x removal from the supplier. One of the conclusions of Reference 2 was that operational choices result in some SCRs not being operated at their highest attainable removal efficiencies.

In 2005, Erickson[3] surveyed a larger population of units for the 2004 Ozone season and examined the effects of catalyst type, ammonia source, technology supplier, and learning over time. Erickson examined the removal efficiency as determined by the average emission rate over the ozone season versus the first quarter NO_x emission rate. Some conclusions reached by Erickson include:

- Catalyst type does not appear to impact the removal efficiency of the SCR.
- Ammonia source may have some impact on removal efficiency of the SCR, data set to small for conclusion.
- 19 units achieved over 90% removal NO_x removal.
- Some units improved their SCR outlet NO_x level over the period as well as the variability in the outlet NO_x emissions.

None of the previous efforts explicitly examined the ability of the SCR to provide consistent NO_x emissions. This effort expands on the previous work by Erickson in that it updates the analysis with 2005 data and also explicitly examines variability in outlet NO_x emissions.

CURRENT EFFORT

In this effort we have evaluated the population of coal SCRs and examined performance and reliability using EPA reported emissions data. Performance is measured on the basis of outlet NO_x emissions and NO_x reduction. NO_x reduction for seasonally controlled units was evaluated by comparing ozone season emissions to first quarter emissions for 2005.

Reliability is more difficult to measure. In this effort we sought indications of reliability to maintain an emission rate. To this end, reliability was analyzed using two measures:

Equation 1. Coefficient of Variation (CV) of the hourly outlet NO_x during the ozone season, where

$$CV\% = (\text{standard deviation of hourly } NO_x \text{ rate})*100/(\text{average hourly } NO_x \text{ rate})$$

The coefficient of variation is a dimensionless number that allows comparison of the variation of data that have significantly different mean values. If CV is greater than 100%, that means that the

standard deviation of the values exceed the average, in such a case the NO_x emissions rates would be greater than the average.

Equation 2. Load Effect (for lack of a better term), Load Effect (LE) was calculated, where

LE% = (((average of hourly NOx rate over ozone season)/(overall ozone season NOx rate))*100) – 100

LE is another dimensionless parameter that indicates how much higher (or lower) the average of hourly NO_x emission rates is compared to the overall rate for the period. Because the reported hourly NO_x rate for any hour is treated equally when taking the average of these values, regardless of the heat input during the particular hour, the average of the hourly NO_x emission rates will normally differ somewhat from the overall NO_x emission rate for the entire season. Therefore, LE is an indication of how the average hourly NO_x rate differs from the overall NO_x emission rate for the period as a result of changes in NO_x emission when unit load changes. If the average of hourly NO_x emission rates over the period exactly equals the overall NO_x, then load changes do not have an effect on NO_x emissions rates and LE will equal zero. For an SCR, LE is an important indicator. Because ammonia to an SCR may be secured at part load or during shutdown, the NO_x emission rate during those periods will increase and LE will be a positive number. On the other hand, if NO_x at part load is lower than at high load (for example, if the SCR and ammonia are left on at the same rate at low load), then LE will be negative. LE gives us a way to measure how important this effect was when analyzing the data for the period in question. As will be shown, some units will show high variability in terms of CV. LE provides a way to determine to what extent the variability is associated with changes in load. In calculating both CV and LE, NO_x rate is measured in lb/MMBtu.

Unfortunately, CV and LE do not fully capture reliability. High variability by either measure can result from normal operating practices, as a result of equipment choices the owner made that limit the load-following ability of the equipment, from other operating choices not associated with varying load, or from equipment problems that impact performance. So, theses measurement provide some insight, but not a complete picture of system reliability.

Analysis Data Set

In this current work, we looked at the following emissions data sets:

1. 2005 hourly ozone season and first quarter 2005 emissions data for all units (including units that do not use SCR) with less than 0.15 lb/MMBtu average NO_x emissions rate for the 2005 Ozone season. After filtering for common stacks and missing data, this group included 219 units.
2. 2005 hourly ozone season and first quarter 2005 emissions data for units equipped with SCR for the 2005 Ozone season where SCR characteristics were known. This included 130 units. However, after filtering for units with missing data to determine variability, this group was reduced to 120 units.
3. 2005 year round emissions data on selected units equipped with SCR.
4. 2002 thru 2005 hourly Ozone season and first quarter 2002 thru 2005 emissions data for three selected units equipped with SCR.

The collection of units that provide the first data set include units that do not have SCR and use other technologies to achieve under 0.15 lb/MMBtu. The collection of units that provide the second data set are combined with our database of SCR installation information to enable us to evaluate if some SCR characteristics impact the performance of the SCR. This gave us a database of 120 units with SCR's and their associated vendor, catalyst type, ammonia source and other unit-specific information. For each of the data sets, the average of the hourly Ozone season NO_x emission rates were calculated, as was the standard deviation. These are used in calculating CV and LE as described earlier.

Analysis of Units With NO_x Emissions Below 0.15 lb/MMBtu During 2005 Ozone Season

Figure 1 shows CV and LE during the 2005 Ozone Season versus 2005 Ozone Season NO_x Reduction (versus 2005 Q1) for the population of boilers with 2005 Ozone Season NO_x emissions below 0.15 lb/MMBtu. Each data point shows the data for one unit. Most of the boilers that have relatively low NO_x reductions are PRB-fired units with combustion controls that are not equipped with SCR. On the other hand, some of the low reduction units are annually operated SCRs. The units with high NO_x removals can be presumed to be equipped with SCR. As shown, there is significant variability across the spectrum. However, there seems to be somewhat more variability – in general - at the higher removal rates. This suggests that there is greater variability with SCR than with combustion NO_x controls. This probably is not surprising because SCR may be secured at times due to system design or operation desires. It is also noteworthy that some units nevertheless achieve high removal efficiencies with low variability. This demonstrates that SCR as a technology is capable of maintaining emissions levels very closely to a particular rate at high removal rates.

Figure 2 shows average hourly Ozone season NO_x emission rate plus/minus the standard deviation in hourly Ozone season NO_x emission rate for these 219 units with 2005 ozone season NO_x below 0.15 lb/MMBtu. Like Figure 1, this Figure shows data from some units that are equipped with SCR and some units that are not equipped with SCR. Also shown on this graph is the overall 2005 Ozone season emission rate – determined by the total emissions divided by the heat input. Each data point and its associated range represent one unit. As shown, some units are achieving very low NO_x emissions rates with very low variability. However, some are not. Notably, the units with the highest variability are not the units with the lowest emissions. As shown on the graph, the average of the hourly NO_x emissions rates does not always match the emissions rate for the season. This is due to low load operations having different NO_x emissions rates than high load operation. In most cases where there is a significant difference, the average of the hourly emission rates is higher than the overall ozone season rate. This difference is what accounts for the LE as described above. In most cases, a larger difference between the average of the Ozone season hourly emission rates and the overall Ozone season rate corresponds with a high standard deviation in the hourly emission rate. This is not surprising because large variations in load that impact NO_x emissions would invariably impact variability in NO_x emission rate. This is illustrated further by Figure 3, which shows the relationship between CV (which is always positive by definition) and the absolute value LE. As shown, CV and the absolute value of LE show a significant degree of correlation, although they are not perfectly correlated. This correlation persists at the same level even if only units with SCR are screened or if CV is compared to LE. So, load changes that impact NO_x emission rates are a significant part of the explanation in NO_x emission rate variability during the Ozone season for all units with low NOx emission rates. But, load changes do not fully explain relationships shown.

Figure 1. CV and LE versus 2005 Ozone Season NO_x Reduction

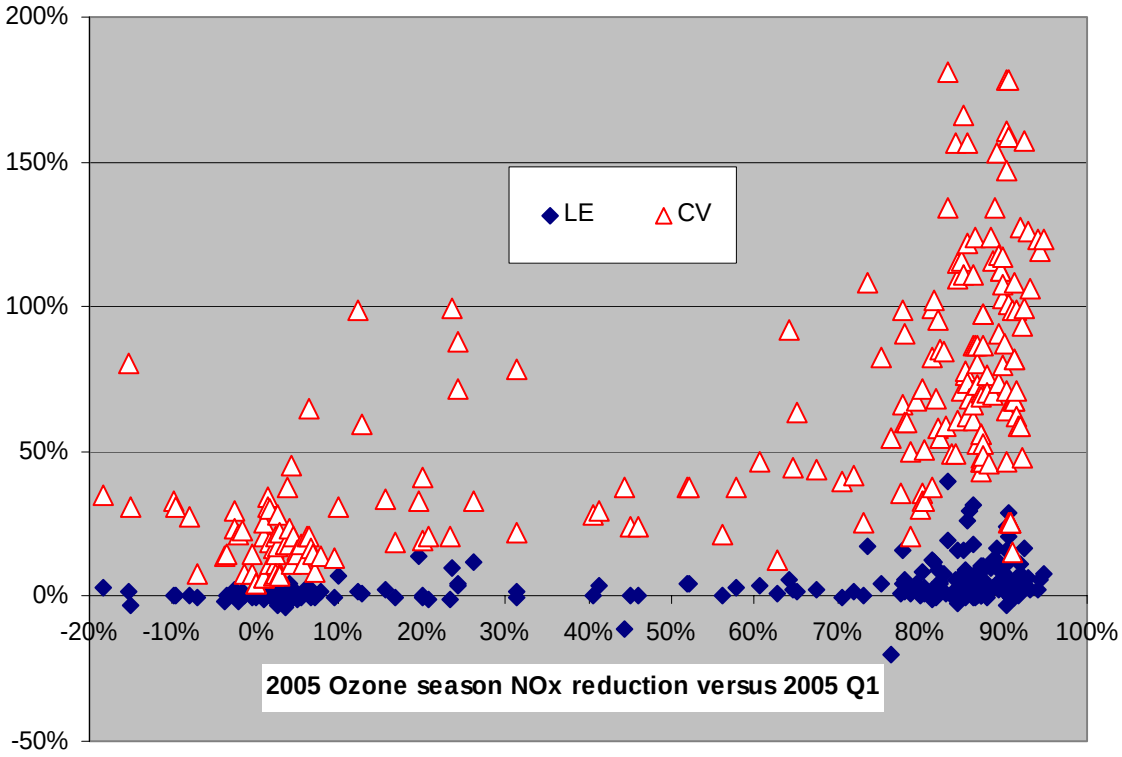
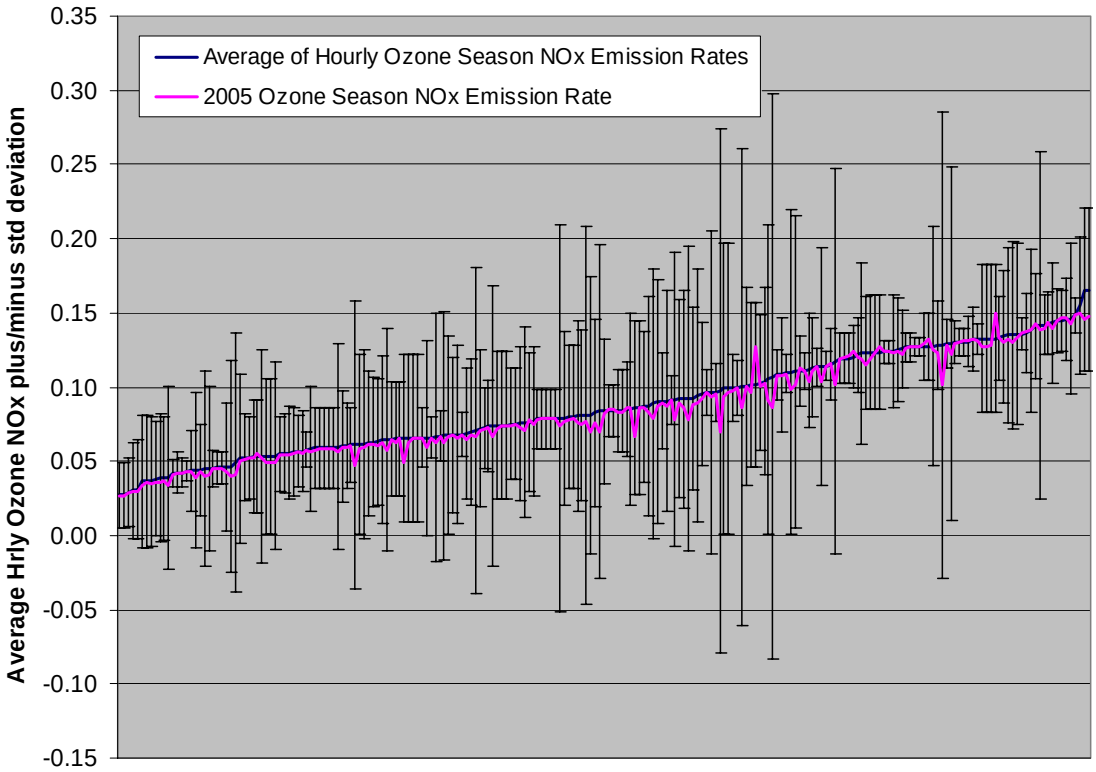


Figure 2. Average Hourly Ozone Season NO_x Emission Rate Plus/Minus Standard Deviation

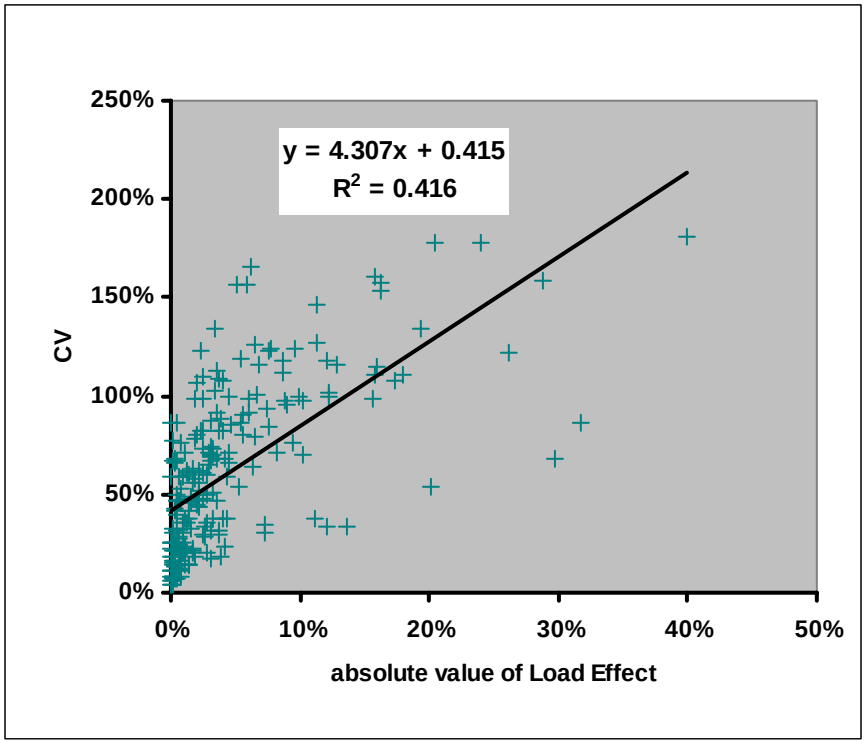


In short, there are two points to be made regarding variation in hourly NO_x emissions during the ozone season.

- The correlation between CV and LE indicates that some significant portion (but not all) of the variation in hourly NO_x emission rates is attributable to changes in NO_x associated with load changes, and may not be indicative of the reliability of the SCR, but simply how the unit is operated.
- Since not all of the variability in outlet NO_x emissions during the ozone season is associated with load changes, there are other factors that affect variability.

Variability in NO_x emission rates during the Ozone season that are not due to load changes may result from operating choices other than load changes, or they may result from other factors that may be associated with reliability. In the following sections we will attempt to isolate some of these specifically as they relate to SCR.

Figure 3. CV versus absolute value of LE for Units with Emissions Under 0.15 lb/MMBtu For 2005 Ozone Season



Analysis of SCR Operation with Different Coal Types

Figure 4 shows CV of hourly NO_x during the 2005 Ozone season versus Bituminous and Powder River Basin (PRB) coals. Nines units of each coal type were selected from the data set described above. Although some units operate on a year round basis, only the Ozone season data was considered. From the selected units the PRB units have an average CV of 48% while the nine bituminous units used for comparison have an average of 93%. The average CV for all 120 units in data set 2 is 43% - slightly below that of PRB units only. While the fuel comparison analysis does not have the large population of units to provide a high degree of statistical certainty it does suggest

that SCR applications on PRB units offer no greater control or reliability issues than Bituminous coal. The Bituminous unit with the lowest CV of all units analyzed was included in the comparison, several PRB units compare within 50% of the lowest CV value and over half of the PRB units shown are within 25% of the lowest overall CV.

Figure 4. CV of Hourly NO_x During the 2005 Ozone Season versus Different Coal Types

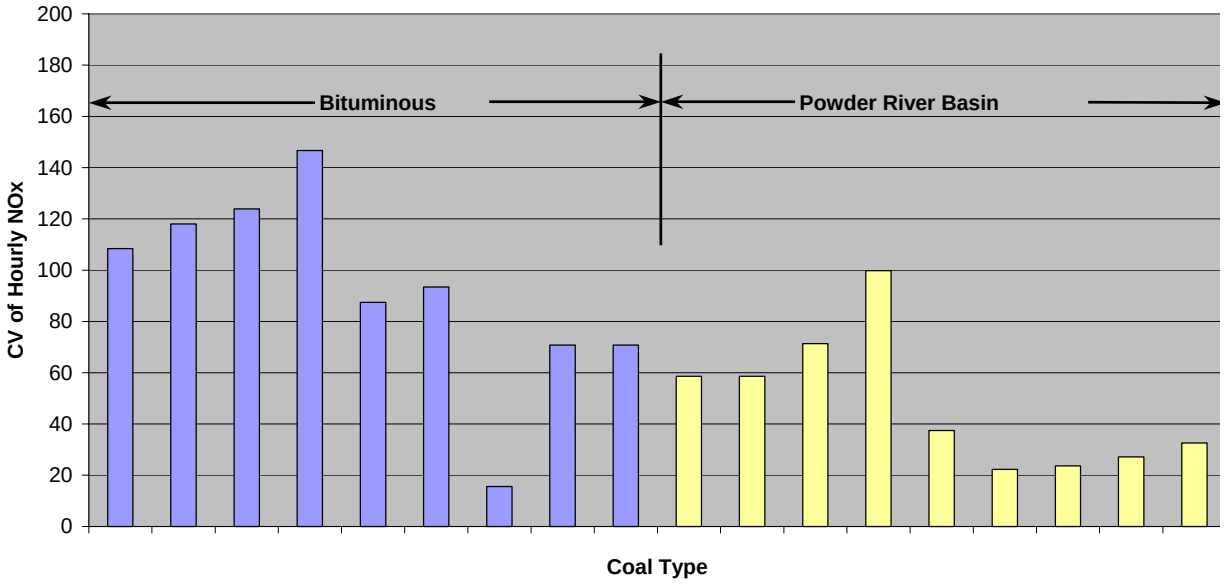


Figure 5 shows Outlet NO_x during the 2005 Ozone season versus Bituminous and Powder River Basin (PRB) coals. The same nine units of each coal type selected for Figure 4 were used in the same order. From the selected units, those fired with PRB have an average outlet NO_x of 0.0554 lb/MMBtu while the nine bituminous units used for comparison have any average of 0.0473 lb/MMBtu. This comparison illustrates that both fuels are very similar in their attainable outlet NO_x values. Some of the PRB units benefit from combustion NO_x controls providing furnace outlet NO_x emission rates significantly lower than those of bituminous units therefore requiring lower removal efficiencies for the same outlet rate. However, higher NO_x removal rates with SCR are being practiced on bituminous units resulting in bituminous outlet NO_x emission rates equal to those of PRB. The LE versus coal type was analyzed; the data indicates no clear trends and considering the small population and the large effect of plant design this data is not presented herein.

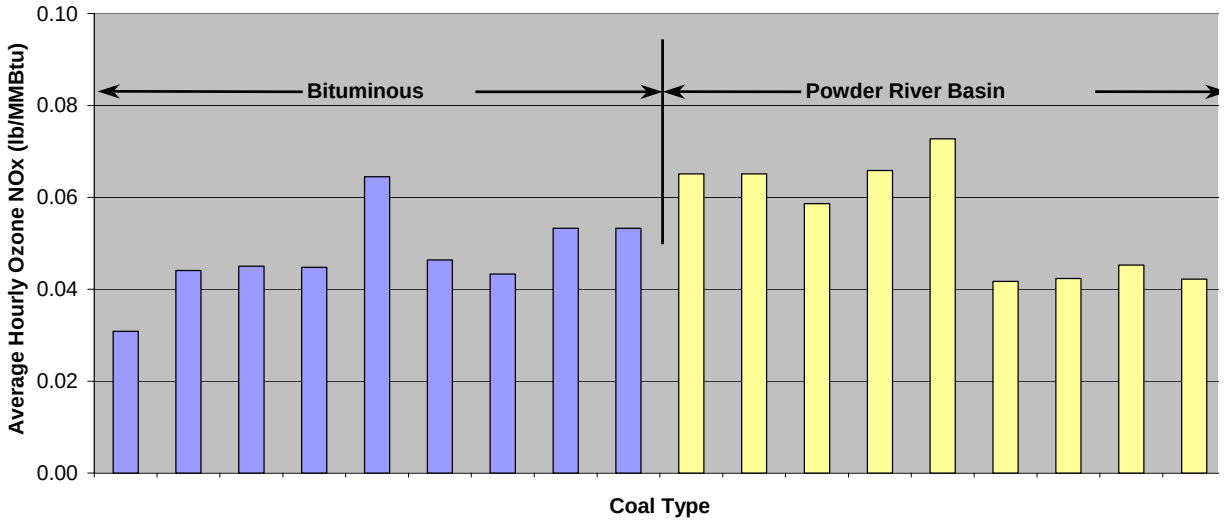
The review of bituminous versus PRB SCR systems indicates two general conclusions:

- SCR systems on PRB fired unit have no greater control or reliability issues compared to bituminous.
- SCR systems on bituminous fired units can attain, with high removal efficiencies, outlet NO_x emission limits in the same range or better than PRB units with combustion NO_x control systems.

The above conclusions on the effect of fuel type are based on a significantly smaller population of data than other analyses present herein. Even with the smaller population these conclusions appear consistent with the basic theory of SCR removal and have been an industry wide concern. One

interesting question raised by this analysis is: Why are PRB units employing combustion NO_x control not operating at high removal rates resulting in even lower outlet NO_x emission rates? The CV of several PRB units appears low enough to support higher removal efficiencies. The low CV, combined with the lower sensitivity of PRB units to ammonia slip, leads the authors to believe that lower emission rates, and higher NO_x removal rates, are attainable with high reliability on PRB units than are currently being practiced.

Figure 5. Average Hourly Ozone NO_x versus Different Coal Types



Analysis of SCR Operation by Catalyst Type, Ammonia Source, Year Commissioned and 2004 versus 2005 Ozone Season Emission

In the work by Erickson[3] using 2004 Ozone season data, it was determined that catalyst type does not appear to significantly impact the removal efficiency of the SCR and that ammonia source may have some impact on removal efficiency of the SCR. In this effort we examined removal efficiency as well as variability in NO_x emissions rates using 2005 data. Also, to see if there were trends indicating operational improvement, we examined reduction efficiency as well as variability in NO_x emission rates based on the year the unit was commissioned. For this analysis we used a population of 120 units equipped with SCR where the characteristics of the SCR – catalyst supplier, system supplier, ammonia source, and year commissioned – were known.

Catalyst Type

Figures 6, 7, and 8 show the results of a sort by removal efficiency, CV and LE, respectively, to illustrate the effects of catalyst type. Consistent with the previous findings of Erickson[3] using 2004 data, catalyst type does not appear to impact removal efficiency. Figures 7 and 8 also show that there does not appear to be an impact on variability in controlled NO_x emission rates. Keep in mind that the data includes some annually controlled units that, because we are comparing Ozone season NO_x emission rates to first quarter NO_x emissions rates, will indicate low removal for these units. The conclusion that catalyst type does not affect removal efficiency, control variability and reliability implies that system design and operation have a greater effect than the type (plate, honeycomb, corrugated, etc.) of catalyst installed.

Figure 6. NO_x Removal Efficiency versus Catalyst Type

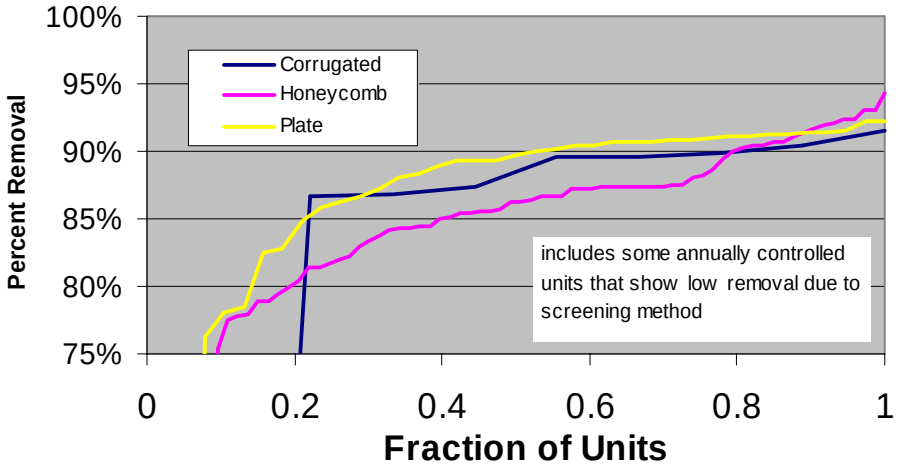
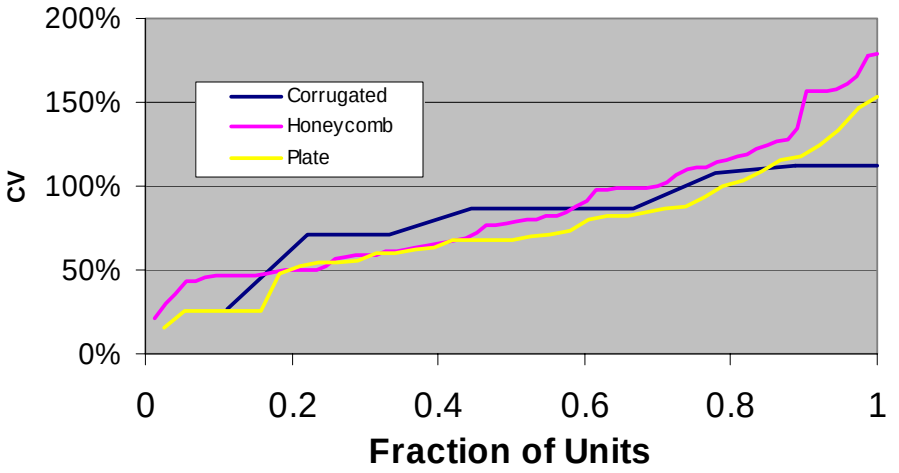


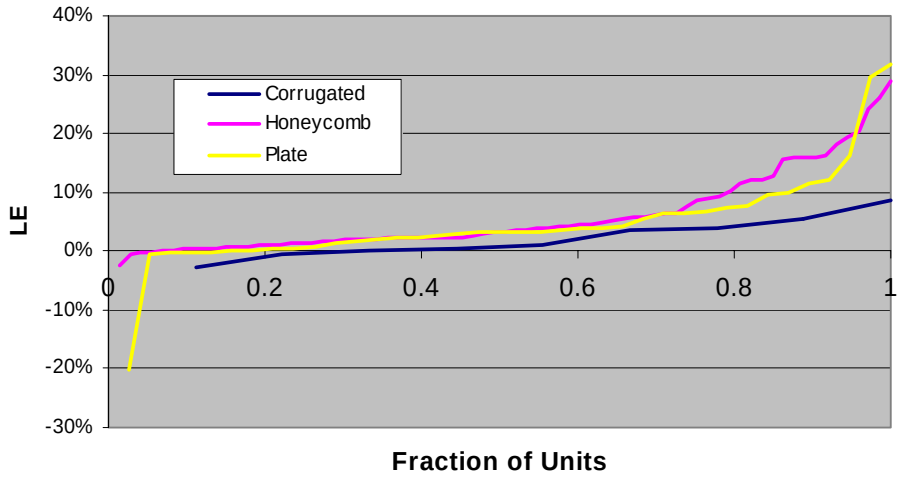
Figure 7. CV versus Catalyst Type



Ammonia Source

Figures 9, 10 and 11 show the results of a sort by NO_x removal efficiency, CV and LE, respectively, to investigate the effects of ammonia source. Consistent with the previous findings of Erickson[3] using 2004 data, the units with aqueous ammonia tend to have lower removal efficiencies than for anhydrous ammonia or urea. The units with aqueous ammonia may show slightly less variability than for the other ammonia sources, but with similar load effect. Due to the small number of aqueous ammonia units relative to anhydrous and urea units, we cannot say that these results are statistically meaningful. Moreover, even if statistically meaningful, this does not mean that aqueous ammonia is the cause of lower NO_x reduction rates on these units – it maybe coincidental that aqueous was used on units with lower NO_x reduction rates by design and we don't know the reason. Again, keep in mind that the data includes some annually controlled units that, because we are comparing Ozone season NO_x emission rates to first quarter NO_x emissions rates, will indicate low removal for these units.

Figure 8. LE versus Catalyst Type



Year Commissioned

Figures 12, 13 and 14 show the results of a sort by removal efficiency, CV and LE, respectively, to see the effects of start up date. Disregarding the data of 2000 and 2005 because there were relatively few units in these dates (3 and 2, respectively), we see that there is little difference in removal efficiency except for possibly 2002, which seems a bit lower at the low end. This effect for 2002 may be due to annually controlled units. Again, focusing on 2001 through 2004, 2004 seems to have higher variability (in both CV and LE) than 2001, 2002 and 2003. This may be indicative of a learning effect where operators take a year or more to develop operating practices at the plant that make the most of the SCR. Since the variability of the NO_x emissions, measured in CV and LE, for years 2001, 2002, and 2003 are close, this may indicate that most of the benefits of learning are achieved in the first year.

Figure 9. NO_x Removal Efficiency versus Ammonia Source

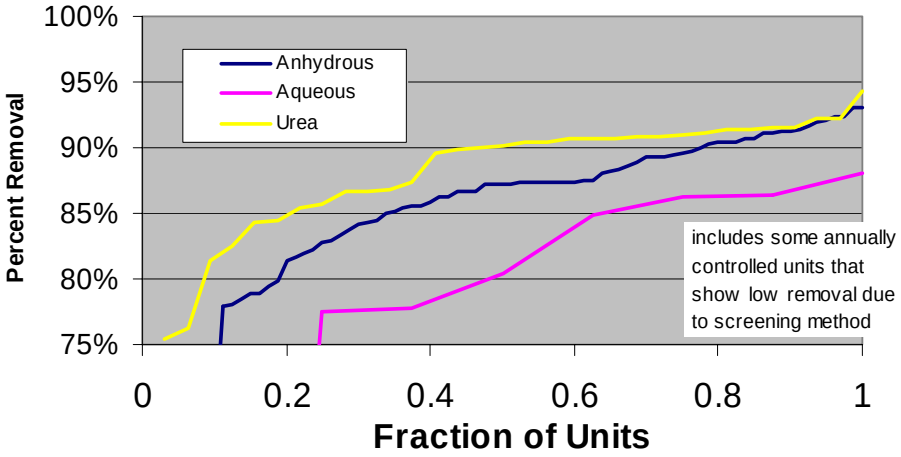


Figure 10. CV versus Ammonia Source

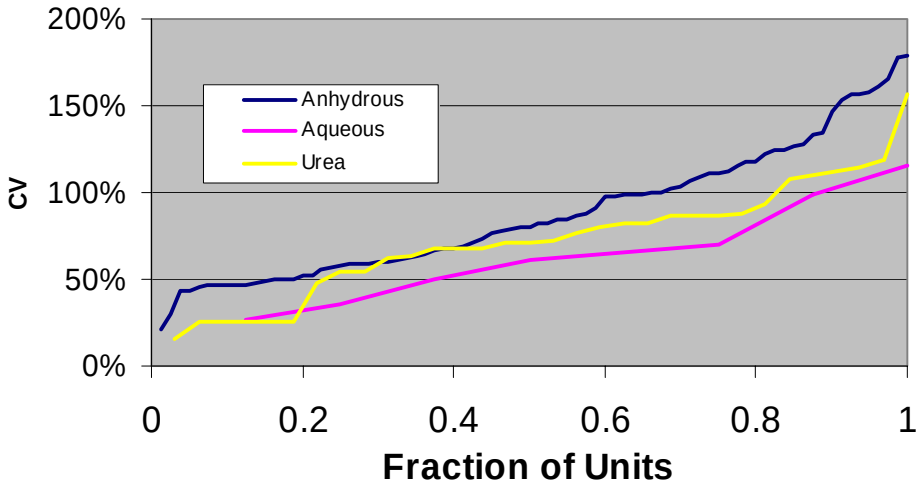
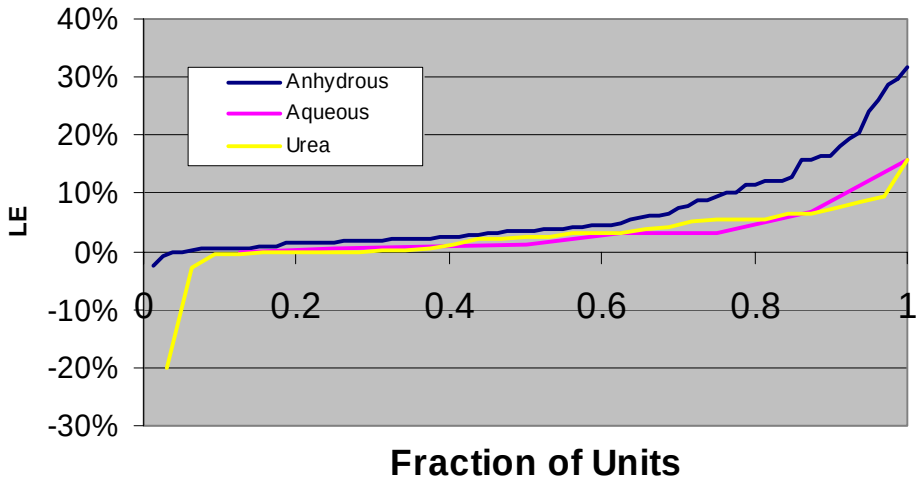


Figure 11. LE versus Ammonia Source



Comparison of 2004 to 2005

Comparison of the units analyzed by Erickson[3] for NO_x removal efficiency in 2004 showed that between 2004 and 2005 71% (or 92 of 130) of the 130 units examined improved their NO_x reduction percentage. Of these units 6% (or 8 of 130) went to annual controls (thus comparison of Q1 to ozone season NOx emission rate to estimate reduction is meaningless) and only 23% (30 of 130) had lower removal efficiency in 2005 than they did in 2004. Figure 15 compares the distribution of removal efficiency for these units in 2004 and in 2005 – sorted from highest to lowest removal efficiency for each year. In Figure 15 it is assumed that the 8 units that controlled annually in 2005 had similar removal efficiencies as in 2004. As shown, nearly 30% of the units achieved 90% or more removal in 2005 while that number was slightly over 10% in 2004. Roughly 70% of the units in 2005 achieved 85% or better removal while in 2004 the percent that achieved 85% or better removal was about 50%. This shows a clear trend toward improved performance between 2004 and 2005 for these units.

Figure 12. NO_x Removal Efficiency versus Year Commissioned

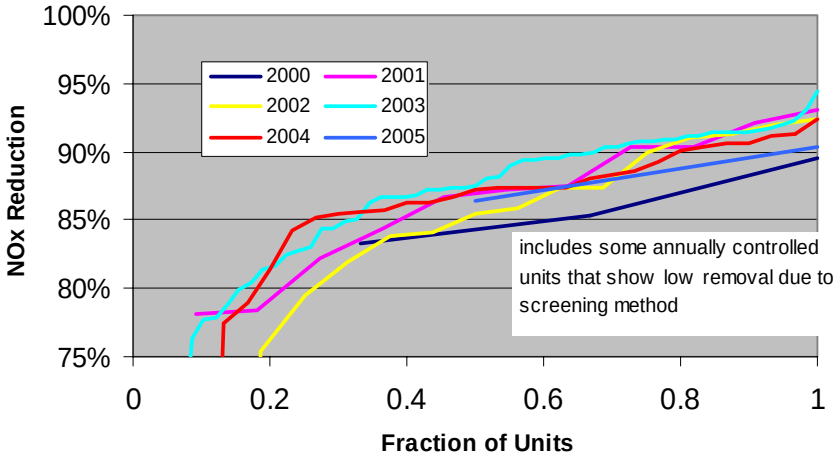


Figure 13. CV versus Year Commissioned

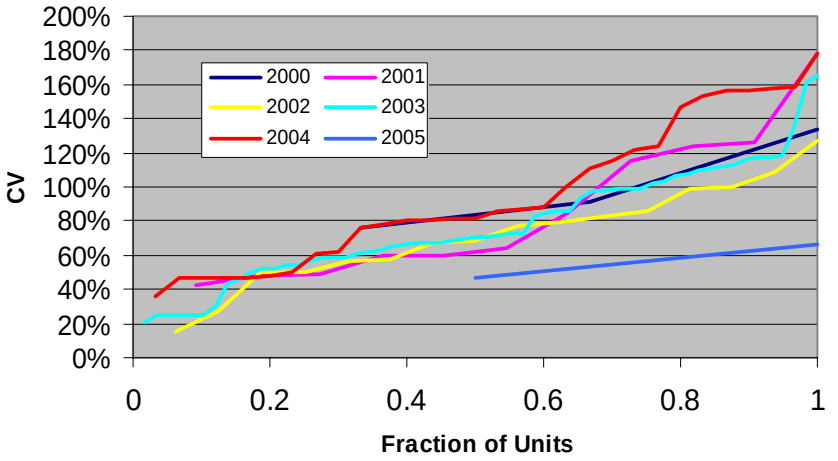


Figure 14. LE versus Ammonia Source

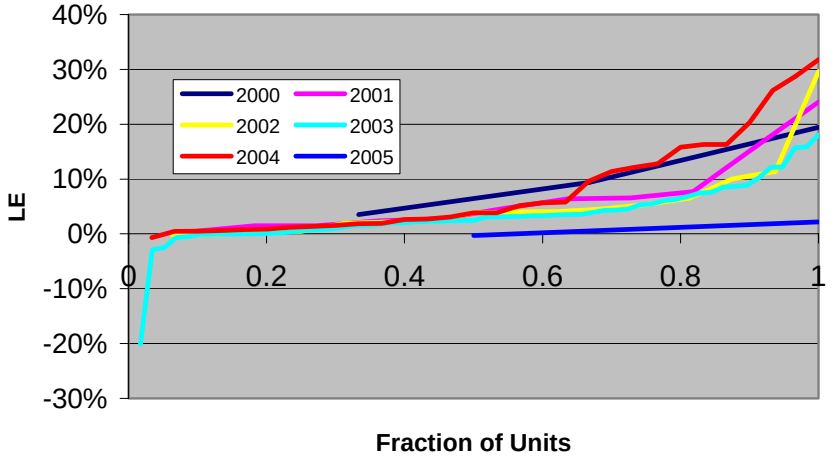
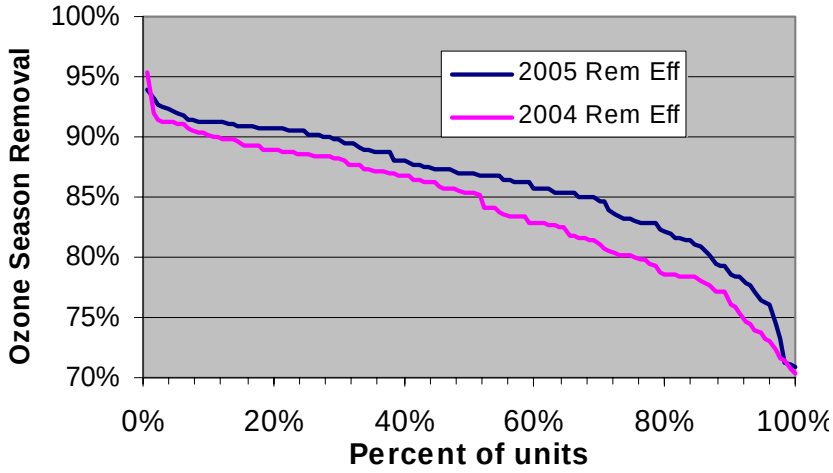


Figure 15. Ozone Season Removal 2004 versus 2005



Analysis of Operational Improvement and Stability Over Time

Figure 16 shows CV of hourly NO_x for three plants versus years of operation. All three plants fire bituminous coal and are greater than 600 MW in size. Plant one was the first SCR plant for the utility and has no SCR inlet temperature controls. Plants 2 and 3 are owned by the same utility, are the same size, and are not the first SCR systems for utility and employ steam side SCR inlet temperature control. Plant 1 uses anhydrous ammonia while plants 2 and 3 uses urea based ammonia. This illustrates variability of CV over time and between plants of similar design. This finding is in contradiction to the single plant analysis by Erickson[3], which concluded that once stable a plant remains stable. Figure 17 shows LE for the same plant over the same time period. This figure suggests that similar plants with the same design and SCR temperature control system can operate differently with respect to NO_x removal as a function of load. The analysis of operational years suggest that operational characteristic of SCR are plant dependent. The cause of this dependence is unknown and has not been investigated at this time.

The conclusions related to CV and LE as a function of years of operation are based on limited data and have not included a detailed investigation of each plant to determine the underlying reasons for the differences. This analysis does indicate that plant operation, even with similar plant and owners, has an effect on the SCR systems operation.

Analysis of Year Round SCR System Operation

Figure 18 shows the CV for 12 year round operating SCR systems; the CV is plotted for both the year and only the Ozone season. Plants 1 through 6 represent early US SCR retrofit plants, plants 7 and 8 are units with the SCR designed as original equipment and the last four (4) plants (9-12) are units designed for Ozone operation that now operate year round. The graph shows considerable variation between plants regardless of above category. Plants with low variability during the ozone season showed low variability year round. The plot also shows increased CV during the Ozone season for most units. This was not expected since it was anticipated that better operation might be found during the Ozone season due to the value of NOx allowances. The increase in CV is most

likely due to plants operating at higher removal efficiencies during the Ozone season resulting in lower outlet NO_x emissions.

Figure 16. CV versus Years of Operation

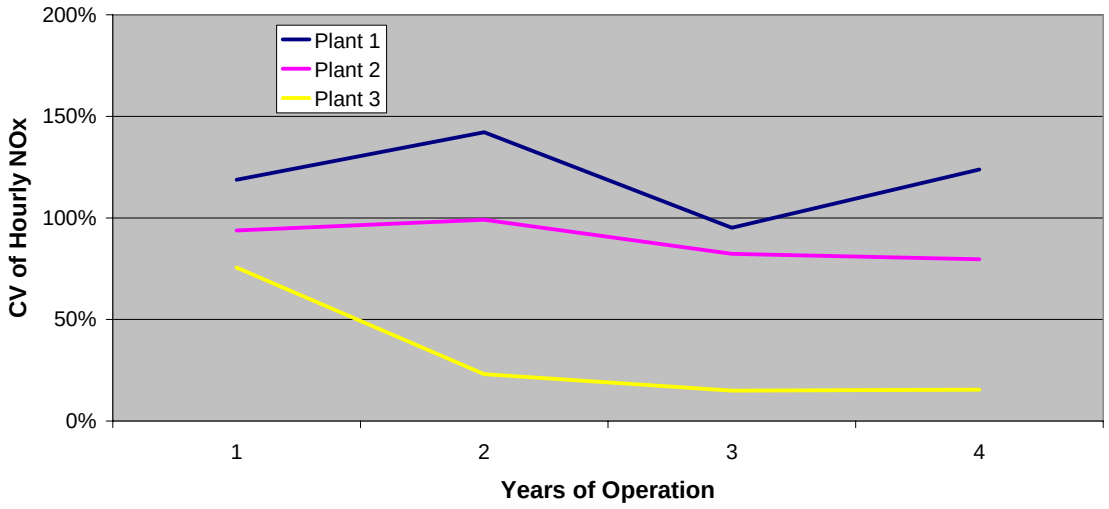


Figure 17. LE versus Years of Operation

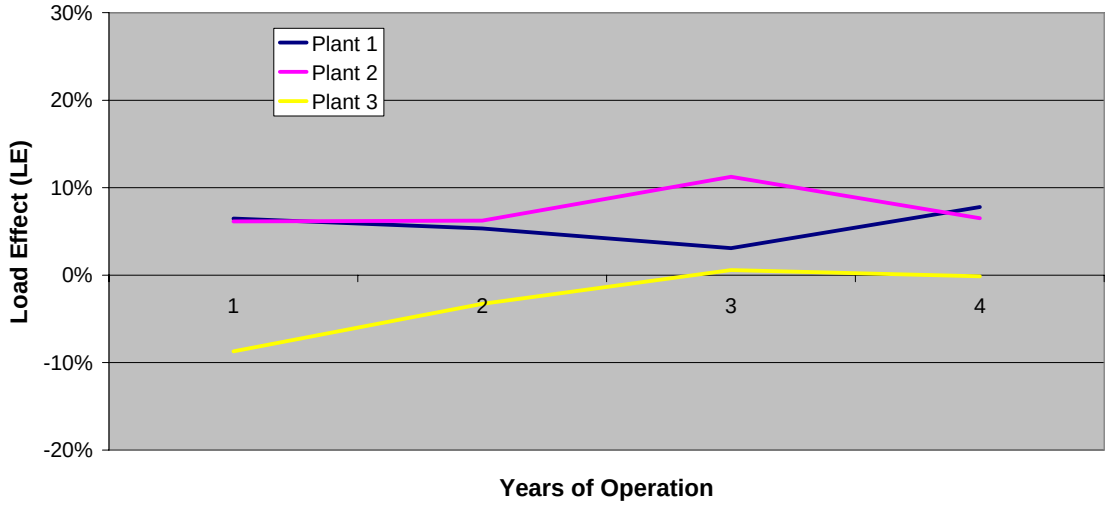
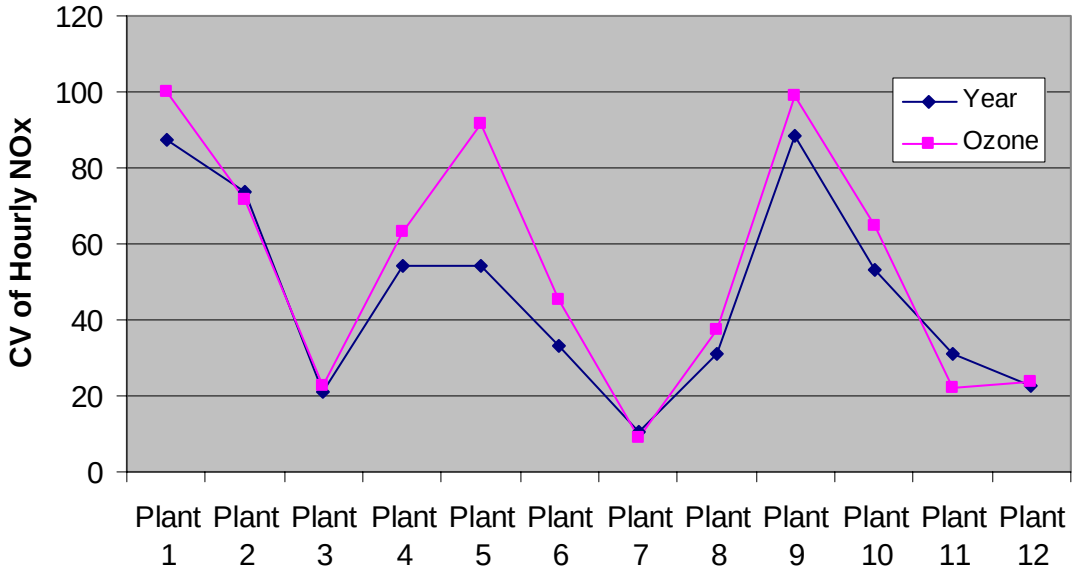


Figure 18. CV versus Year Round SCR Operation



CONCLUSIONS

In this work we examined the performance and reliability of SCRs on US coal-fired utility boilers. Performance was measured in terms of NOx removal and in terms of outlet NOx levels. Reliability is more difficult to measure. However, we used measures of variability of outlet NOx as an indicator of the SCR's reliability in providing NOx control. One of the twos measures of variability was used to determine the significance of load in the variability of outlet NOx level. We have reached the following conclusions from this work.

- Ninety percent (90%) removal efficiency is currently being achieved by a significant portion of the coal-fired SCR fleet. And, performance measured in terms of NOx removal efficiency appears to be improving for the majority of units.
- High levels of variability were demonstrated for units equipped with only combustion controls and for units equipped with SCR controls, although the highest variability was for units equipped with SCR. However, some of the units with SCR achieved high NOx reduction (over 90%) with low variability.
- The units with the highest absolute variability in NOx emissions rate were not the units with the lowest outlet NOx emissions rate. In fact, the data showed some units with very low outlet NOx emissions rate (below 0.05 lb/MMBtu) and very low variability. This shows that low emissions rates can be achieved with high reliability.
- A significant amount of variability, although not all, is associated with changes in load. So, some significant amount of variability in outlet NOx is associated with operating practices.
- Bituminous units with SCR are achieving similar NOx emissions as PRB units with SCR, although the PRB units have a lower combustion NOx level, This, along with the low variability of PRB emissions, suggests that lower NOx emission rates (higher NOx removal rates) are possible from PRB units.
- Catalyst type does not appear to have a significant impact on reduction or variability.

- The choice of anhydrous ammonia or urea as the ammonia source does not appear to impact reduction rate or variability. Aqueous ammonia may show different behavior, but it is difficult to determine since few units in this study used aqueous ammonia.
- There does appear to be a learning curve that benefits both NOx removal and variability in controlled NOx emission rates. This learning has resulted in significant improvements in NOx removal performance across the fleet of SCRs. Reductions in variability appear to be occurring as well.
- Annually controlled units that showed low variability, appeared to do so year round. Variability was usually higher in the ozone season, possibly due to higher NOx removal rates.

FUTURE AREAS OF INTEREST/QUESTIONS

This study examined reliability from the perspective of variability of NOx emissions rate. This may not be the best indicator of reliability. Future work may examine other measures of reliability.

ACKNOWLEDGEMENTS

The authors wish to acknowledge the contribution of Sue Erickson for downloading data and the significant data manipulation required to allow this analysis.

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[2] Staudt, J., Khan, S., and Oliva, M., "Reliability of Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Systems for High Pollutant Removal Efficiencies on Coal Fired Utility Boilers", 2004 Combined Power Plant Air Pollution Control Mega Symposium, August 30-September 2, 2004, Washington, DC.

[3] Erickson, C., "Availability of the US SCR Fleet", EPRI SCR Workshop, November, 2005, Louisville, KY.

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Selective Catalytic Reduction System Performance and Reliability Review

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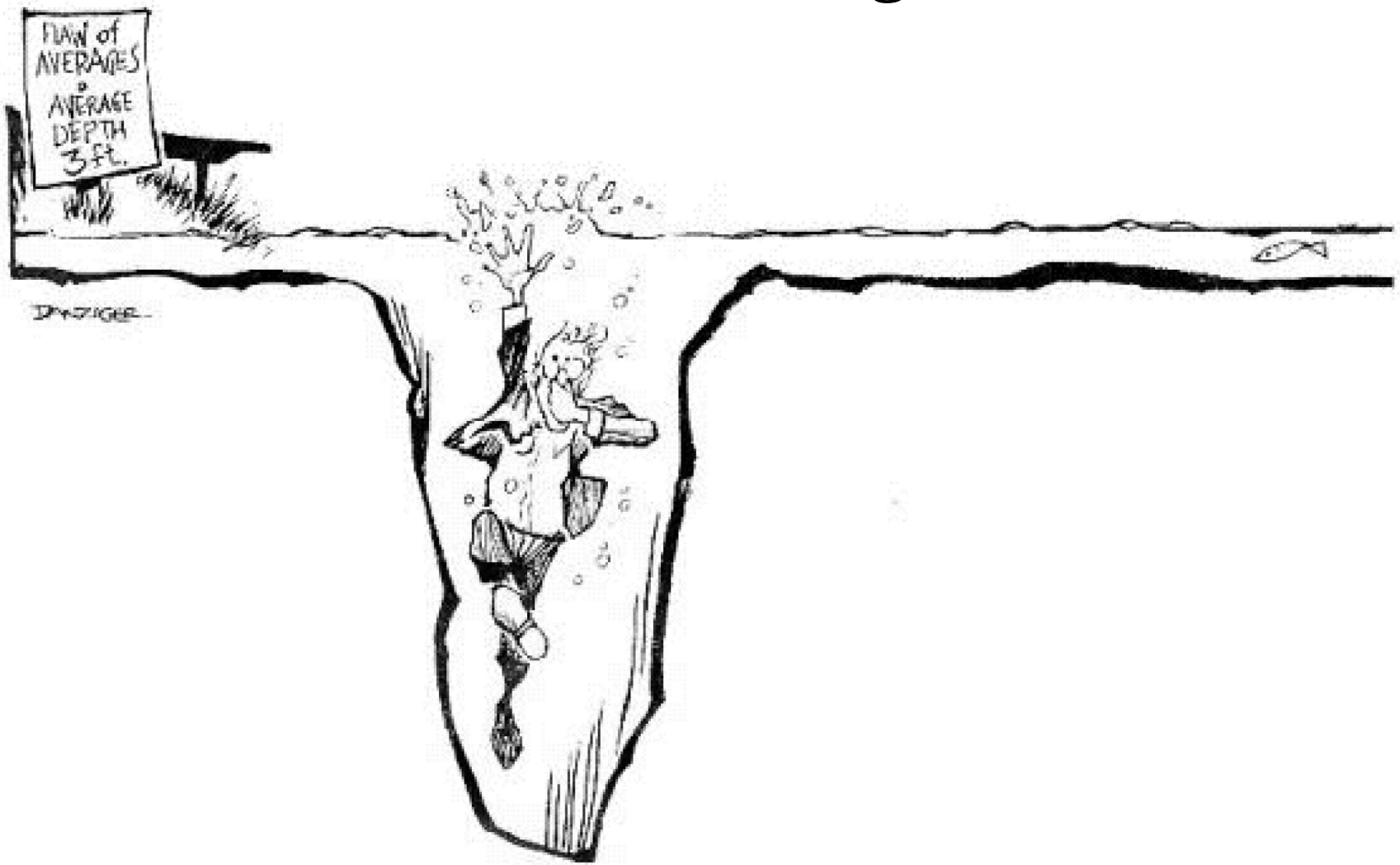
Flaw of Averages



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Past Work

- Study One
  - Focused on ability to meet removal efficiency
  - Number of SCR systems analyzed small
- Study Two
  - Focused on removal efficiency
  - Considered operational choices
- Study Three
  - Analyzed more units
  - Investigated effect of system design and arrangement

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Current Work

- Investigated two parameters to measure reliability
  - Coefficient of Variation (CV)
  - Load Effect (LE)
- Evaluated data sets
  - 2005 hourly emissions less than 0.15 lb/MMBtu
  - 2005 hourly emissions on SCR equipped, Ozone and yearly
  - 2002 thru 2005 on select SCR systems

Reliability Parameters

- Coefficient of Variation (CV)
  - Dimensionless number allows comparison of variation with different mean values
  - If CV greater than 100% indicates values standard deviation greater than average for data set
- Load Effect (LE)
  - Dimensionless number comparing average hourly emission to overall emission based on mass emitted
  - Measure of load effect on SCR ability to operate

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Emissions and Removal Efficiency

- All data obtained from EPA Electronic Data Reporting (EDR) website
- Ozone season emissions determined from may 1st to September 30th
- Removal efficiency calculated using 1st quarter emissions as uncontrolled based

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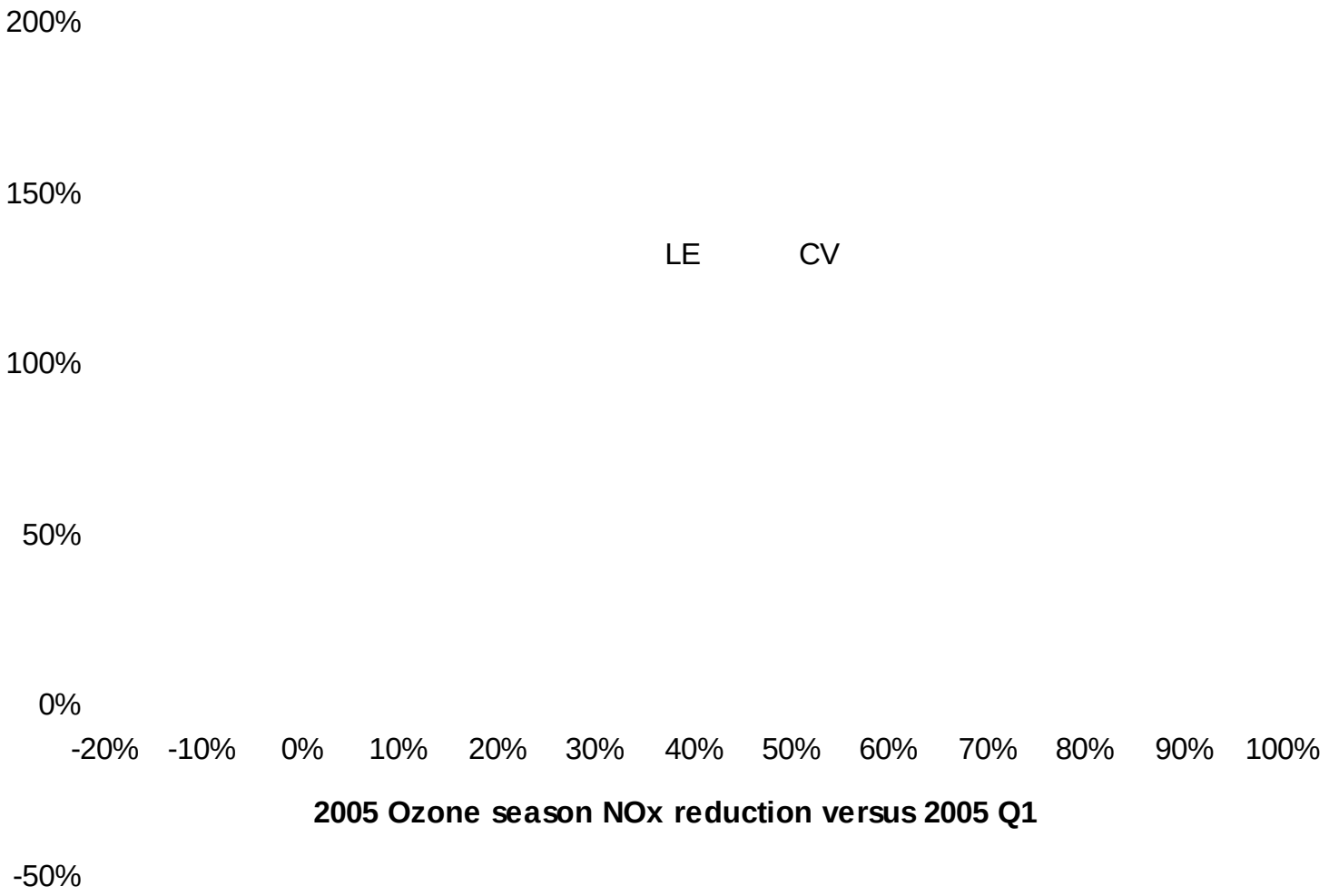
Units with NO_x Emissions Below 0.15 lb/MMBtu for 2005 Ozone Season



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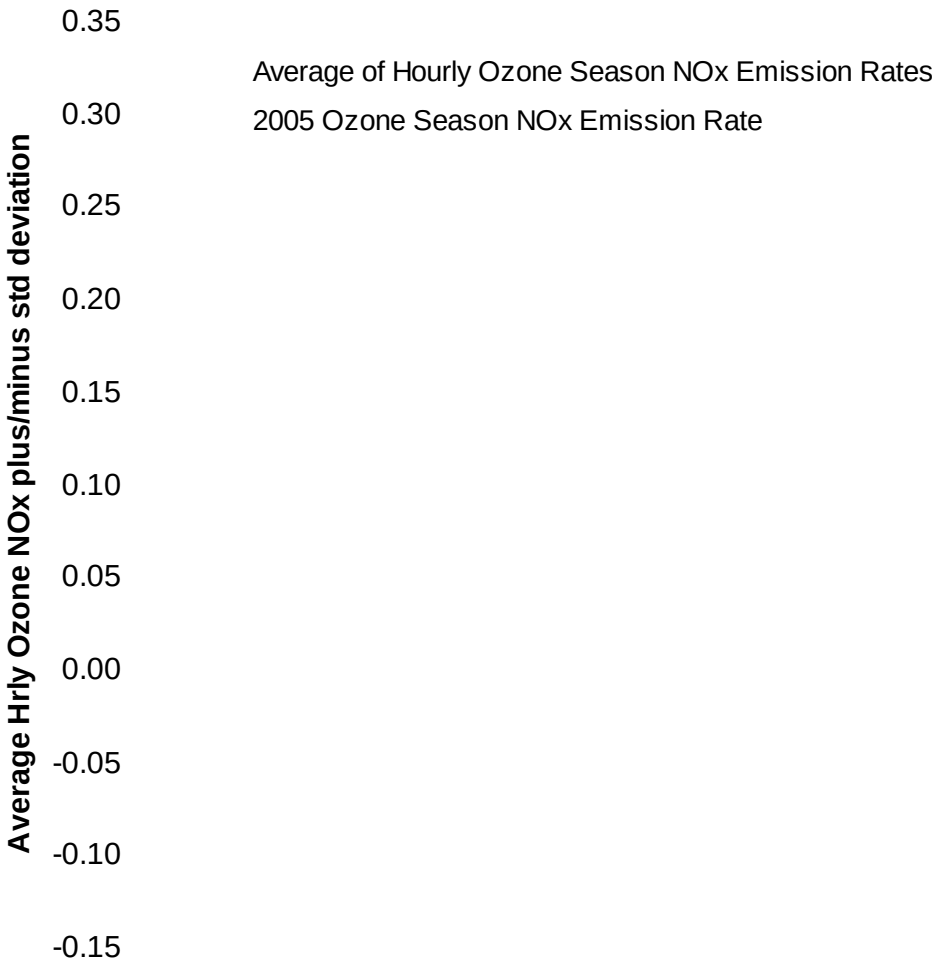
Units with NO_x Emissions Below 0.15 lb/MMBtu for 2005 Ozone Season



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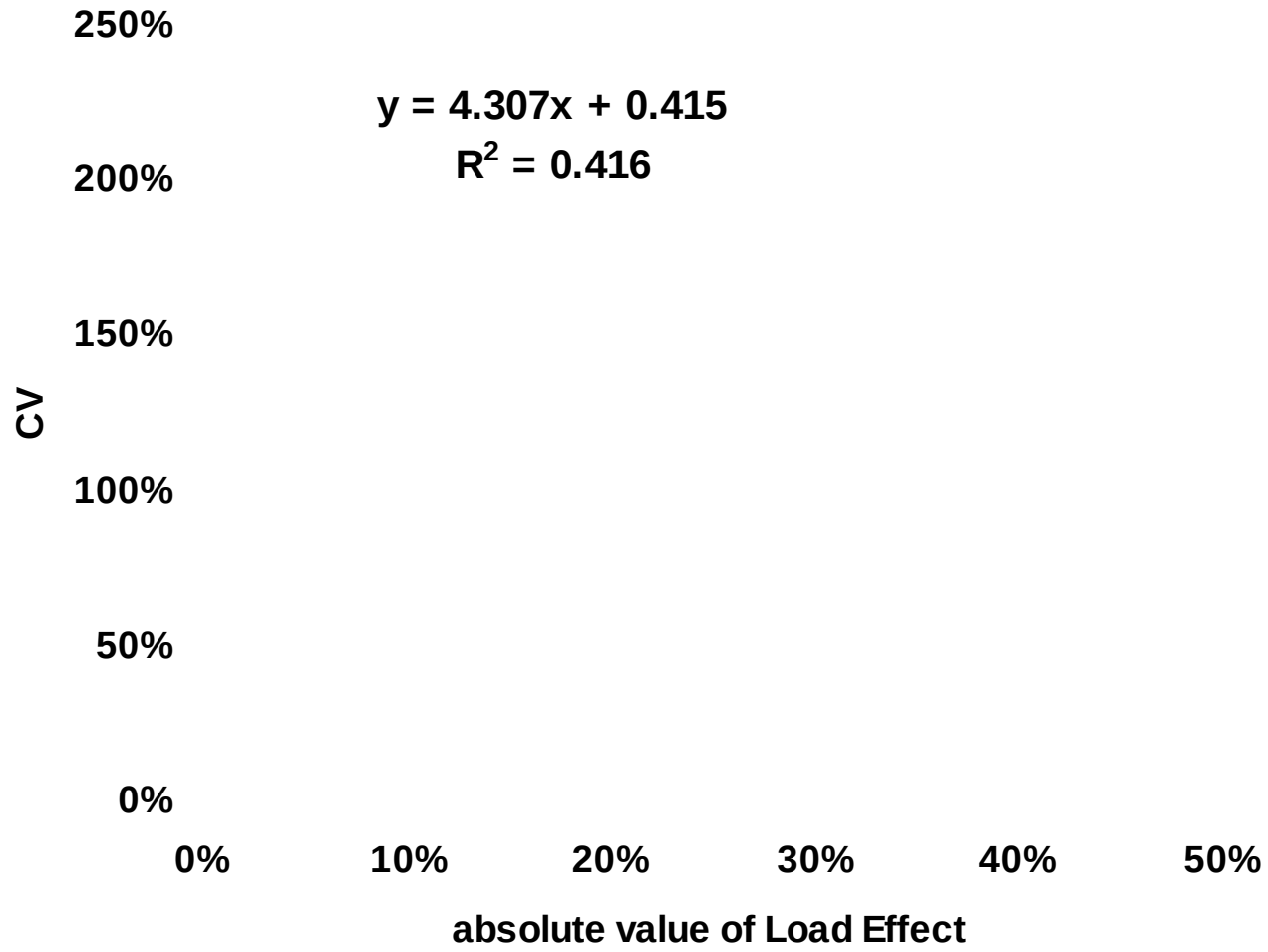
Units with NO_x Emissions Below 0.15 lb/MMBtu for 2005 Ozone Season



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Units with NO_x Emissions Below 0.15 lb/MMBtu for 2005 Ozone Season

- CV & LE correlation indicated some, not all, variation associated with load change
- May not be indicative of SCR reliability but how unit is requested to be operated
- Not all variation associated with load change, other factors resulting in variability

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2005 Ozone Performance for Units Equipped with SCR Systems

- Effect of bituminous vs. PRB coals
- Effect of catalyst type
- Effect of ammonia source
- Effect of year commissioned
- Comparison of 2004 to 2005 Ozone season operation

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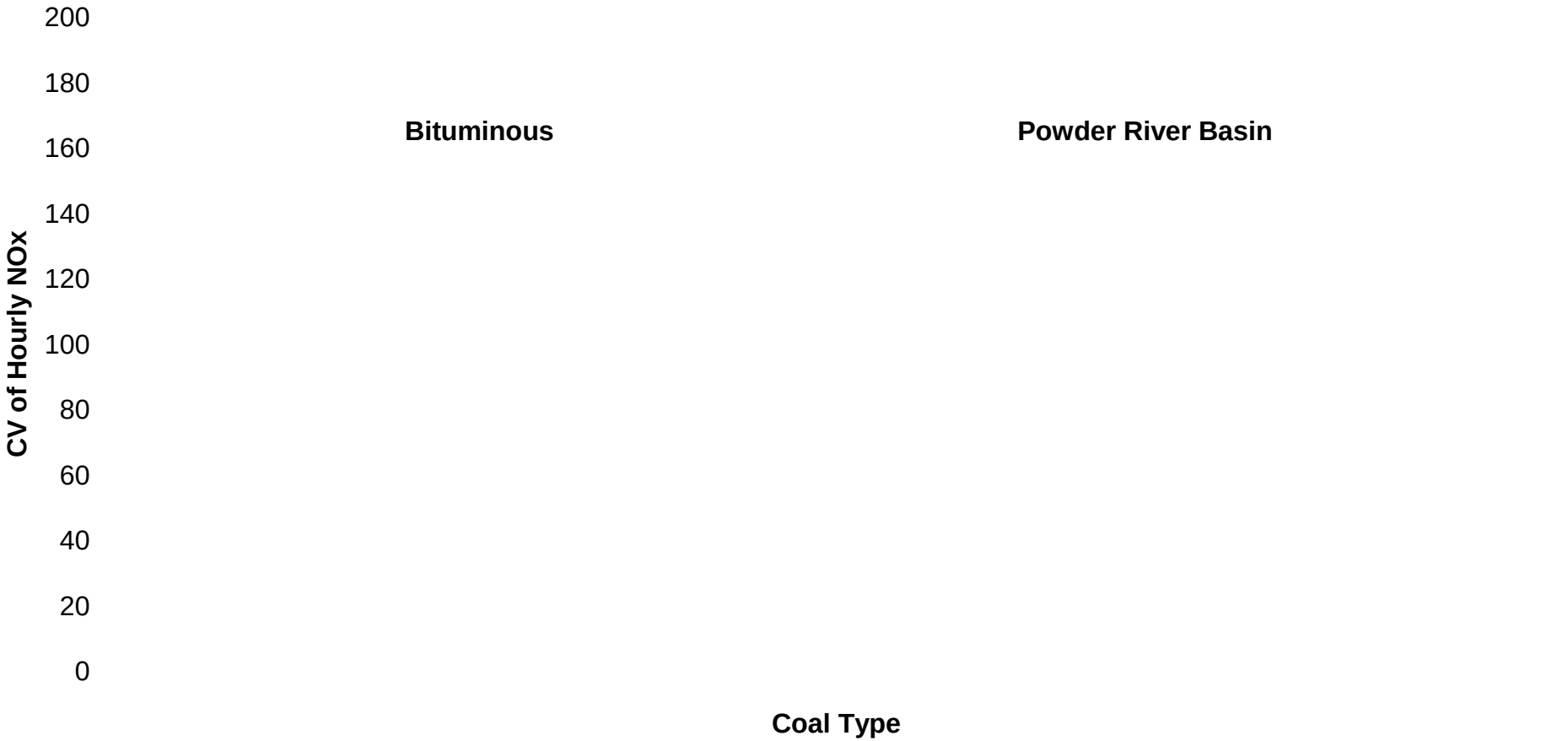
Effect of bituminous vs. PRB coals



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Effect of bituminous vs. PRB coals

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Effect of bituminous vs. PRB coals

- SCR systems on PRB fired unit have no greater control or reliability issues
- Bituminous SCR systems can attain same range of outlet NO_x as PRB
- Small data set for analysis
- Appears PRB units could operate with removals of bituminous resulting in lower outlet emissions

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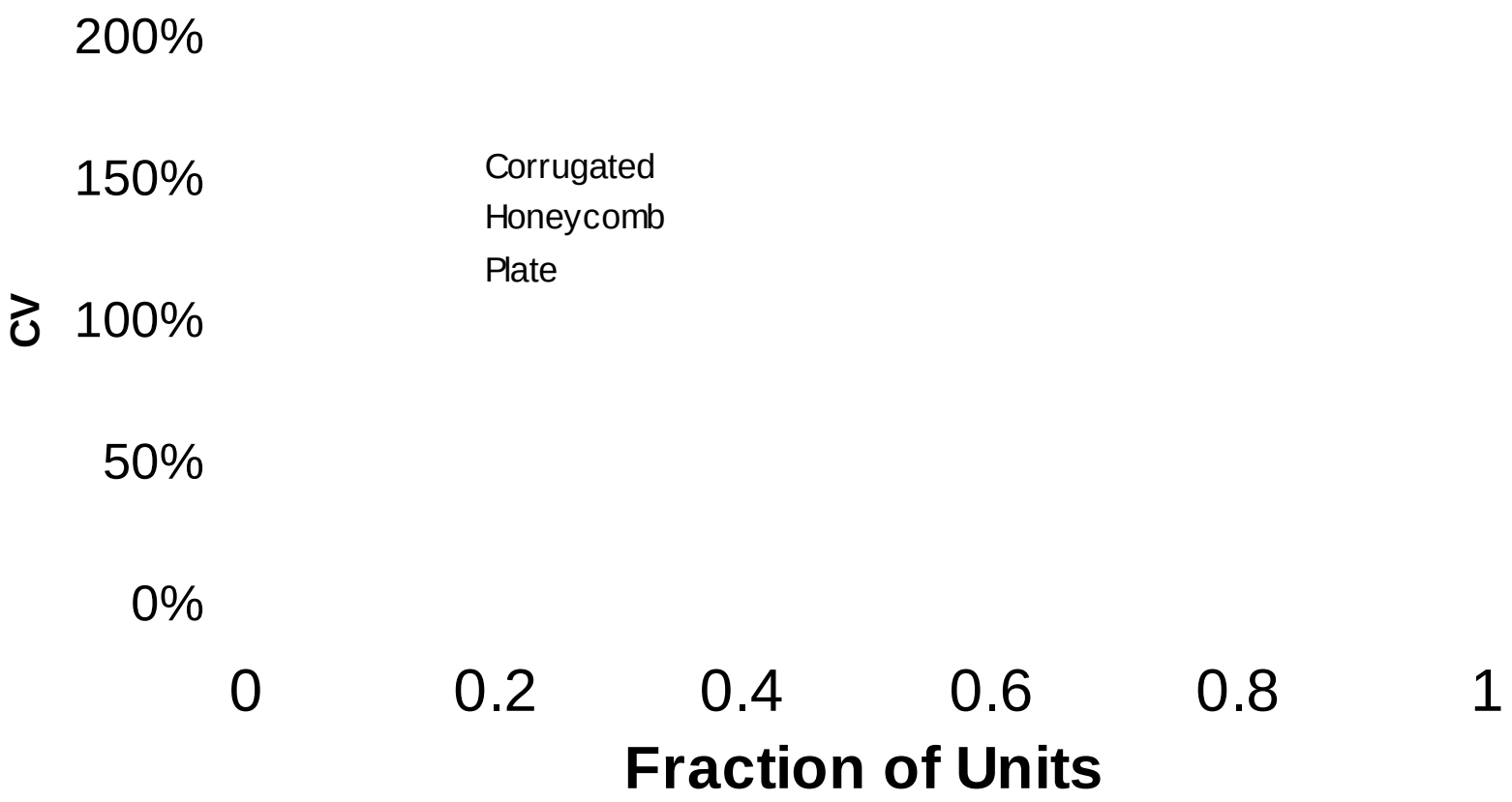
Effect of Catalyst Type



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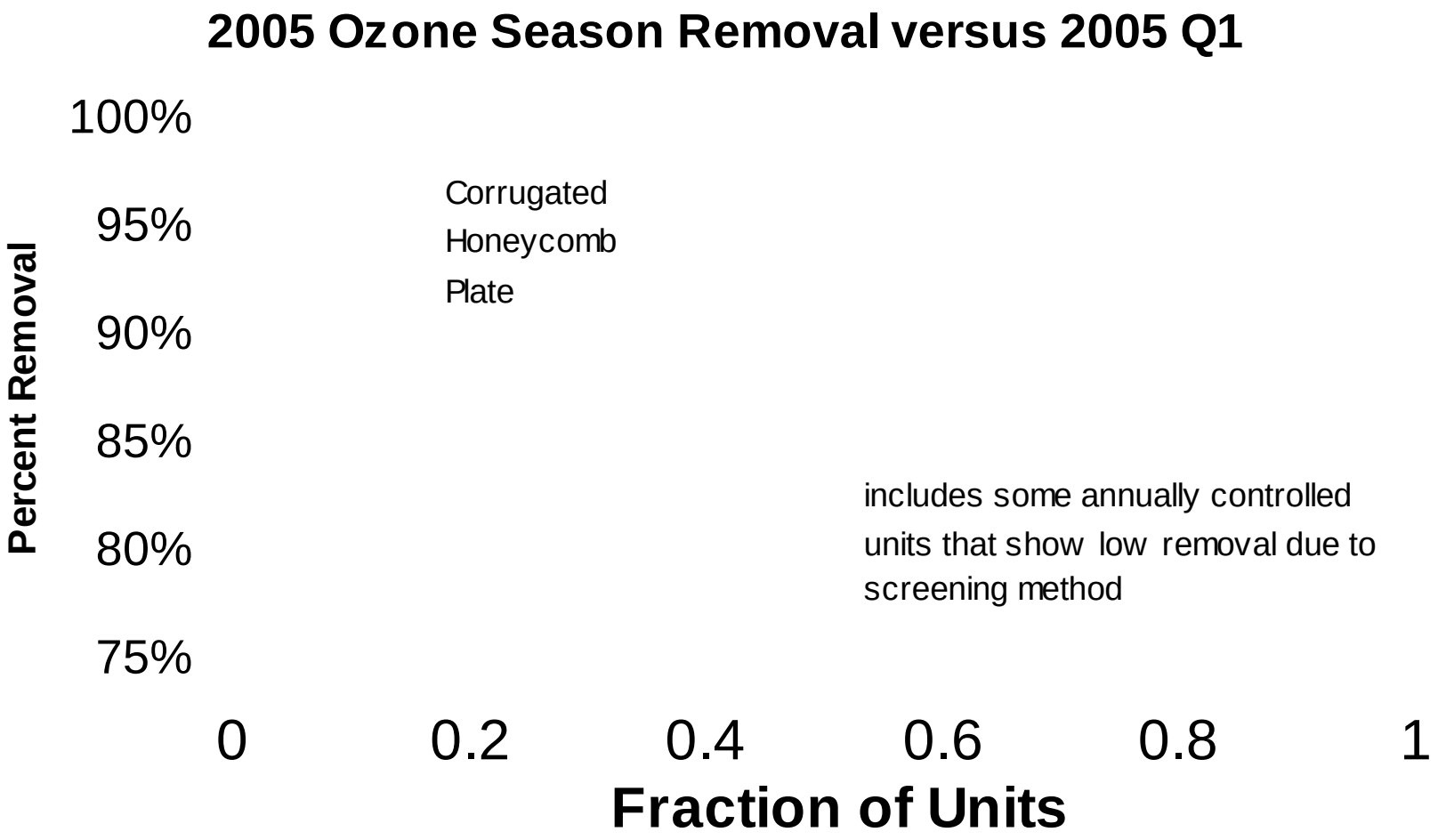
Effect of Catalyst Type



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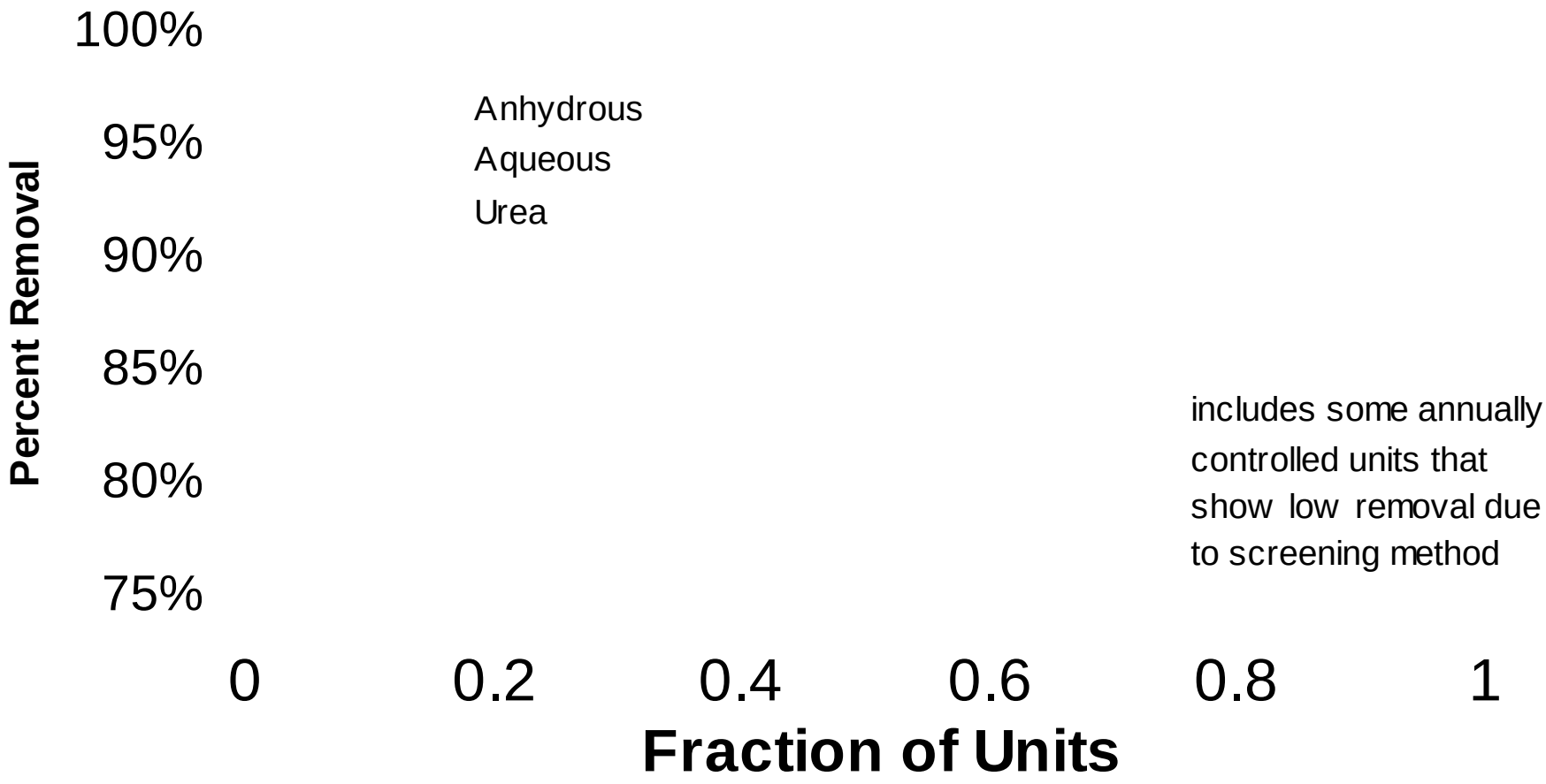
Effect of Ammonia Source

2005 Ozone Season Removal versus 2005 Q1



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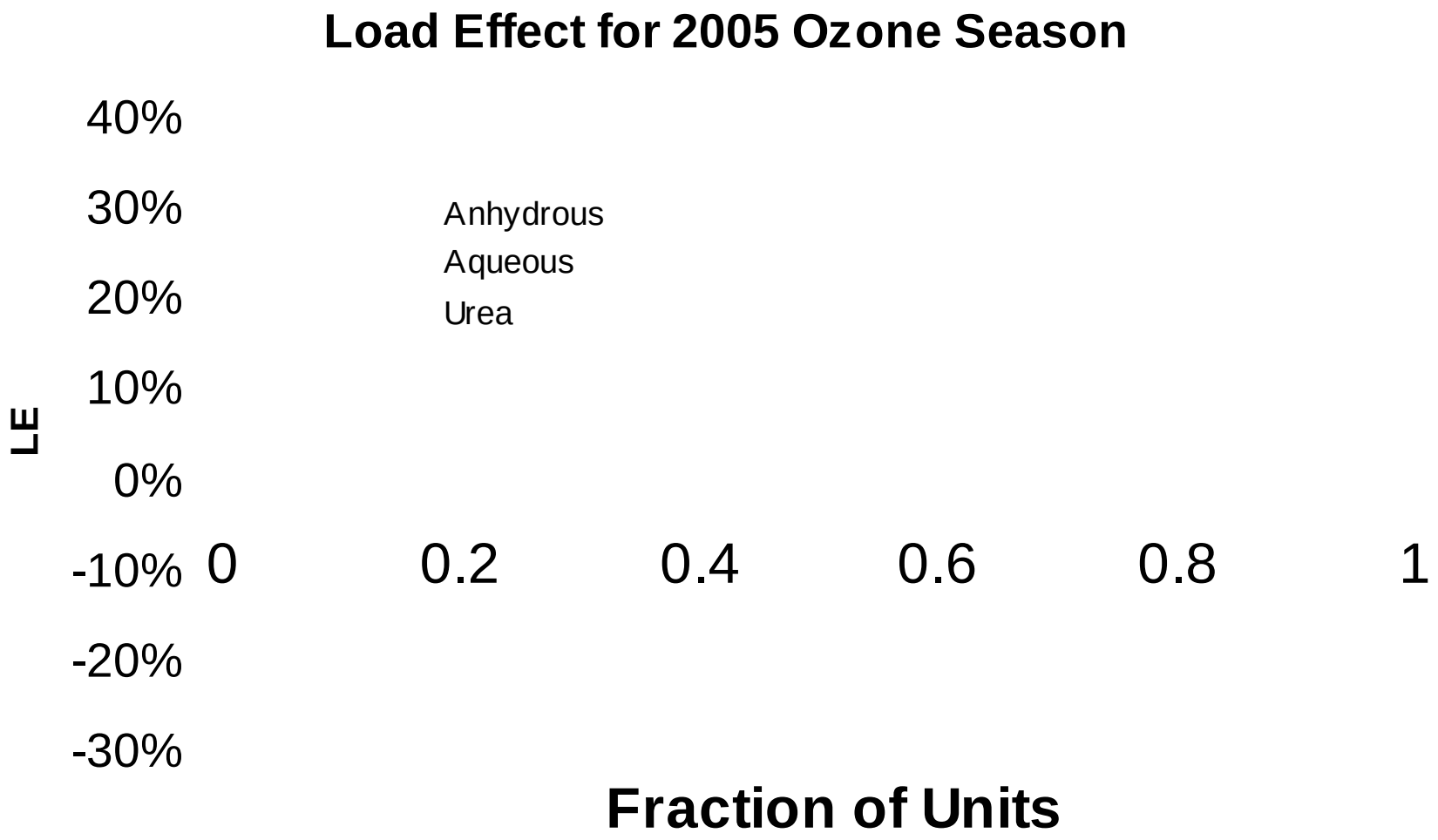
Effect of Ammonia Source



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Effect of Catalyst Type and Ammonia Source

- Catalyst type does not affect removal efficiencies, control variability or reliability
- System design and operation have greater influence than catalyst type
- Aqueous ammonia appears to affect removal efficiencies, no other affect found
- Ammonia source data set statistically small for aqueous, conclusion questionable

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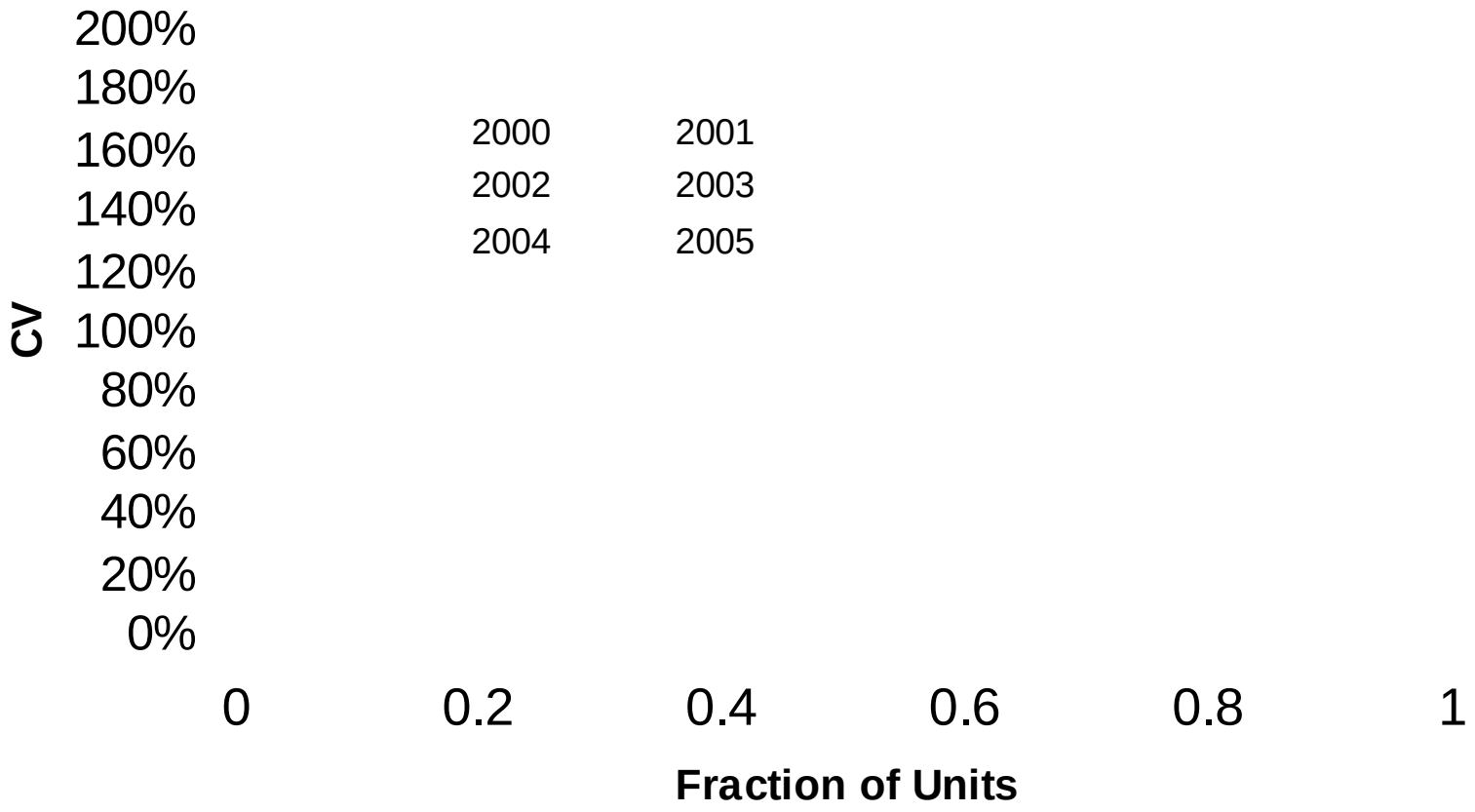
Effect of Year Commissioned

CV during 2005 Ozone Season



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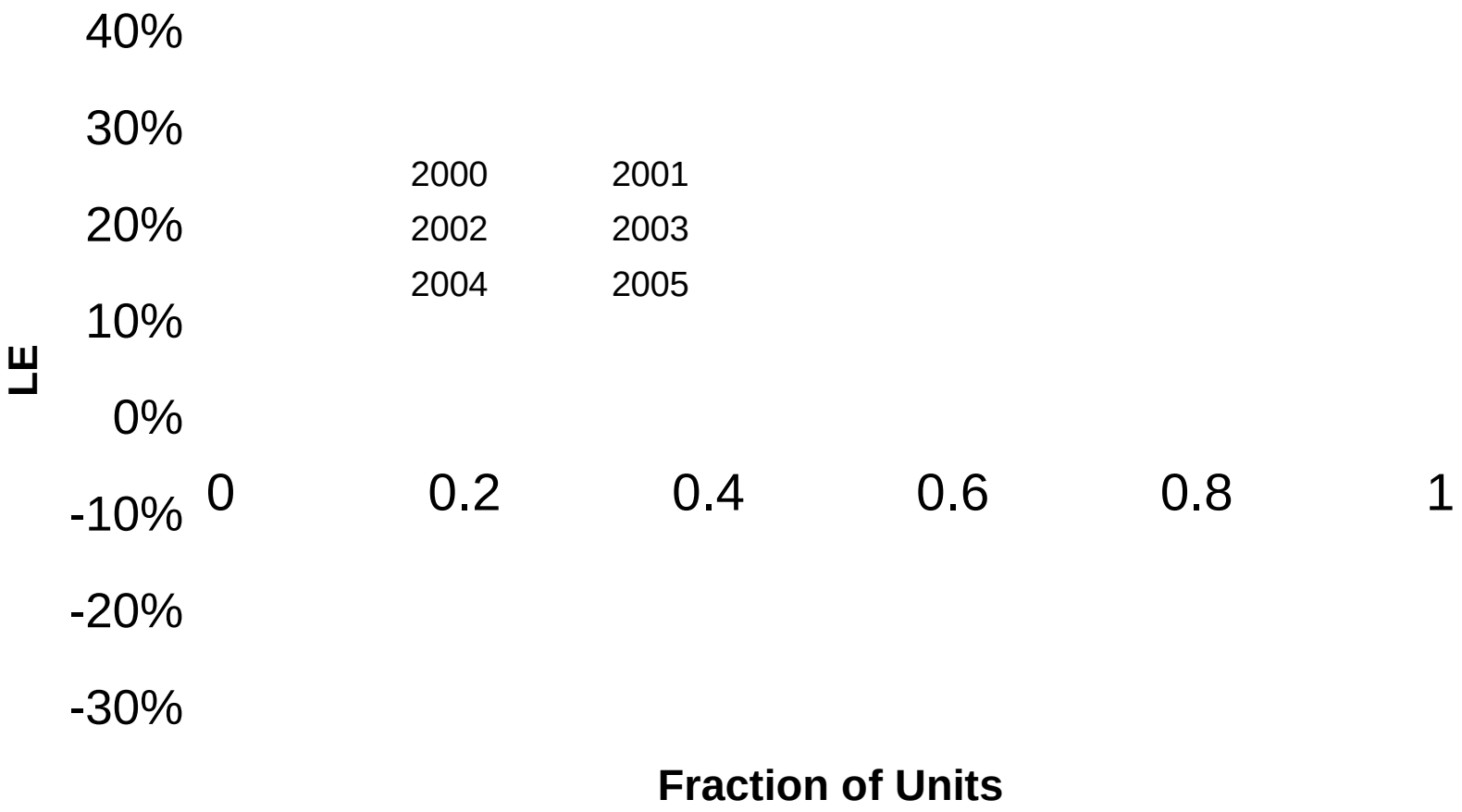
Effect of Year Commissioned

Load Effect during 2005 Ozone Season



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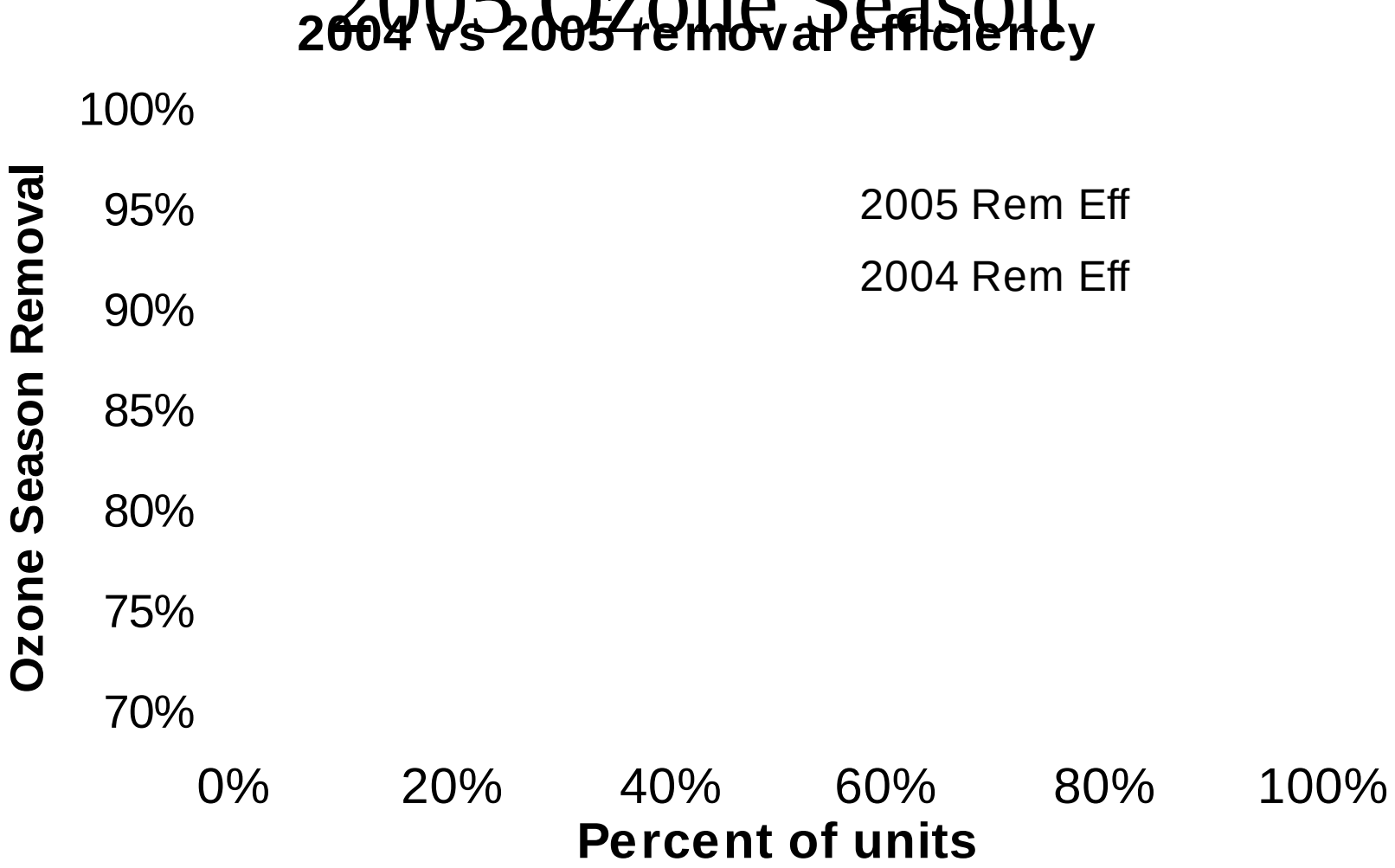
Comparison of 2004 vs. 2005 Ozone Season



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Effect of Year Commissioned

- 2000 and 2005 data contains small number of units and is not considered
- Operator require at least one year to develop operating practices
- Most benefits learned in first year
- 2004 vs. 2005 marked increase (10% to 30% respectively) in units greater than 90% removal

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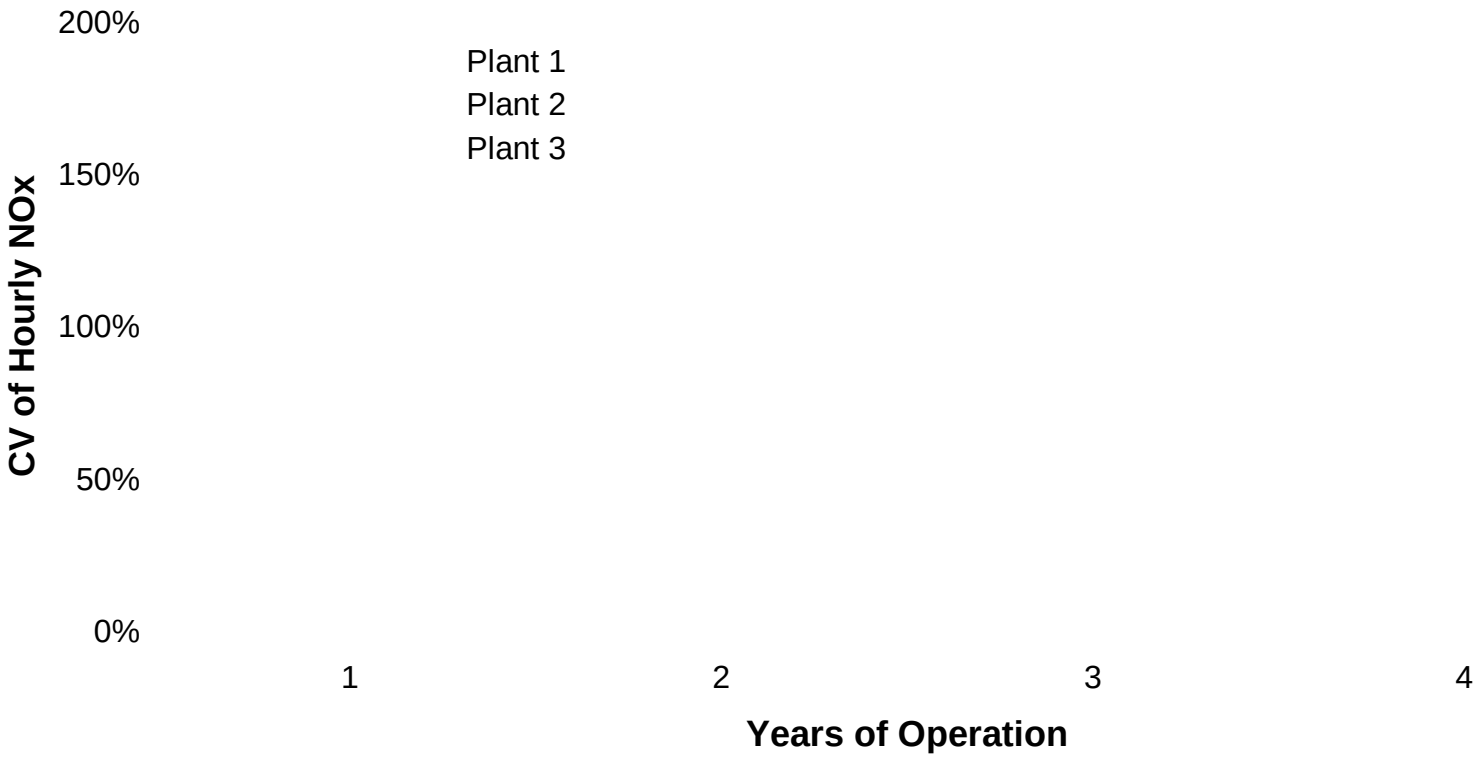
Operational Improvement and Stability Over Time



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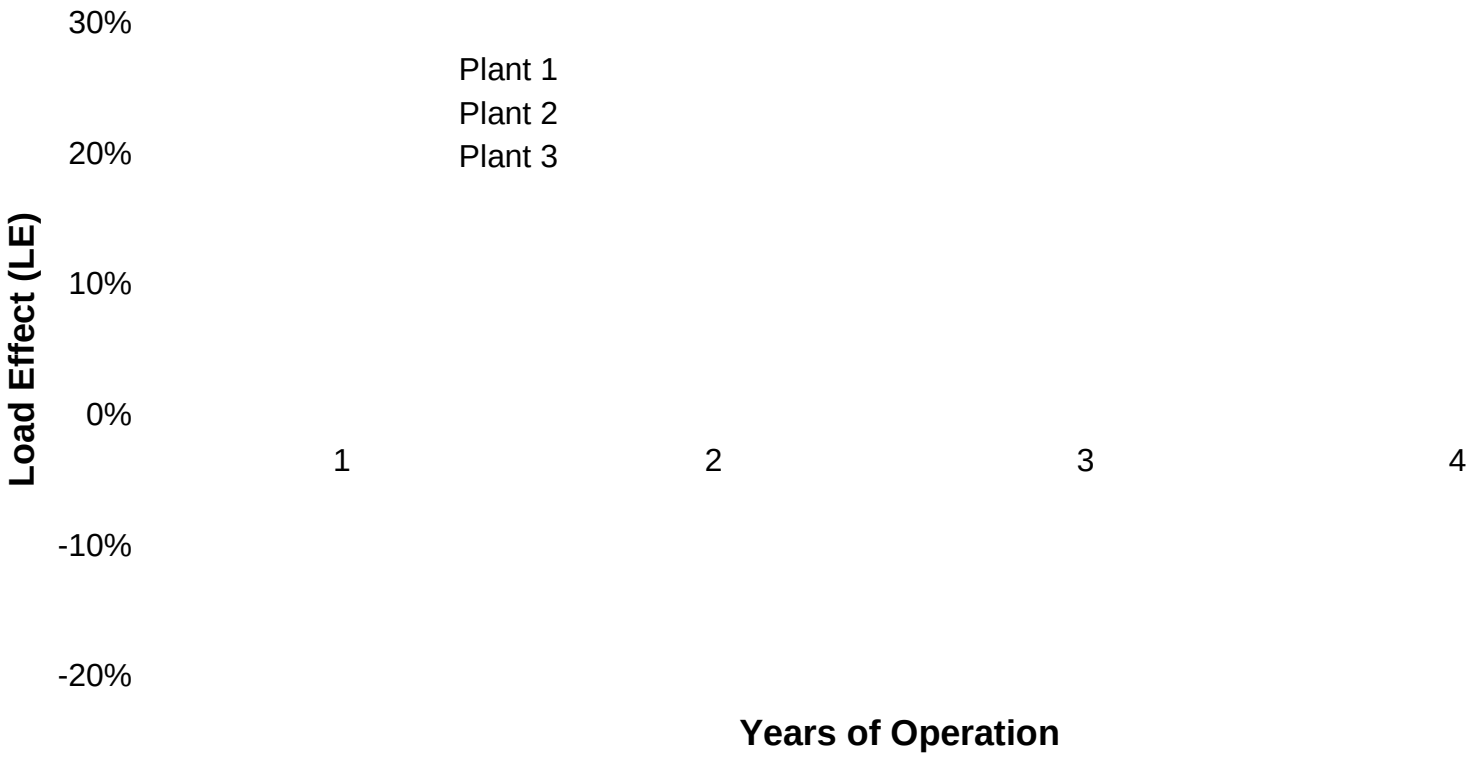
Operational Improvement and Stability Over Time



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Operational Improvement and Stability Over Time

- Three bituminous coal greater than 600 MW investigated
- Plant 1 uses anhydrous ammonia while Plant 2 and 3 use urea based ammonia
- Plant operations play major role even with same design and utility
- Certainty and number of conclusion limited based on available data set

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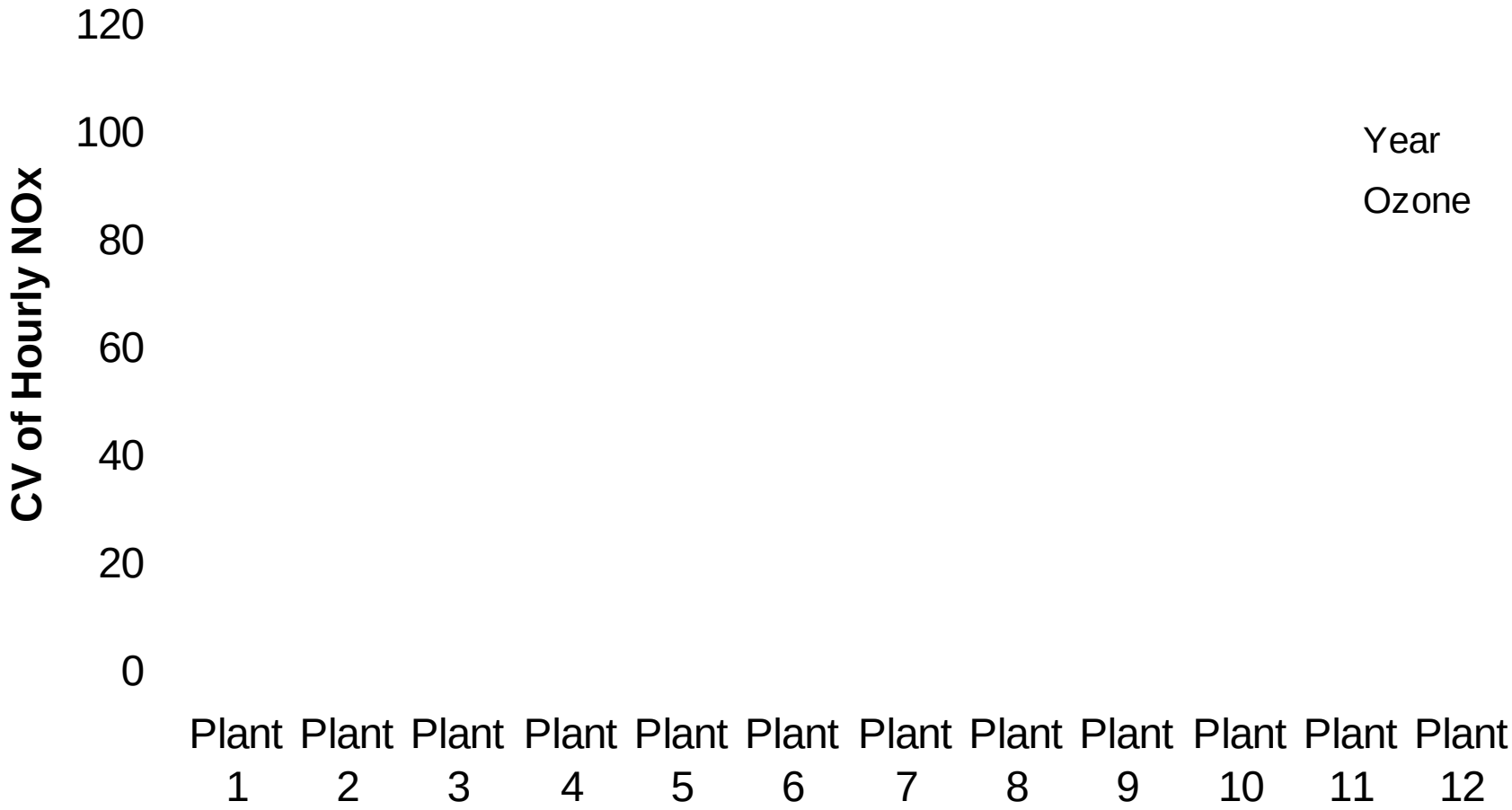
Comparison of Ozone vs. Year Round Operation



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Comparison of Ozone vs. Year Round Operation

- Plants 1 – 6 early SCR retrofits
- Plants 7 & 8 original Ozone units operated year round
- Plants 9 – 12 designed with boiler
- Low variability during year typically resulted in low for Ozone
- CV increases for Ozone season on almost all, possibly due to increase NO_x removal
- Considerable variation of CV between 12 plants

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Conclusions

- 90% NO_x removal being achieved by significant portion of US fleet
- High CV demonstrated for units with combustion only and SCR NO_x control equipment
- Units with highest CV not units with lowest absolute emission rates
- Outlet NO_x variability associated with operational practices
- Bituminous SCR units achieving similar outlet emissions rates

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Conclusions

- Higher removal rates with PRB possible with current control variability
- Catalyst type shows not impact on NO_x removal or variability
- Ammonia source appears not to impact performance, incomplete data for aqueous ammonia
- Significant learning occurring across fleet resulting in increase in unit above 90% removal
- Ozone season variability greater than year round possibly do to increased removal efficiency

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Future Areas of Interest

- Determine other measurable SCR performance and reliability attributes
- Attempt to access plant by plant difference that affect performance
- Investigate method of determining affect of plant operations on performance

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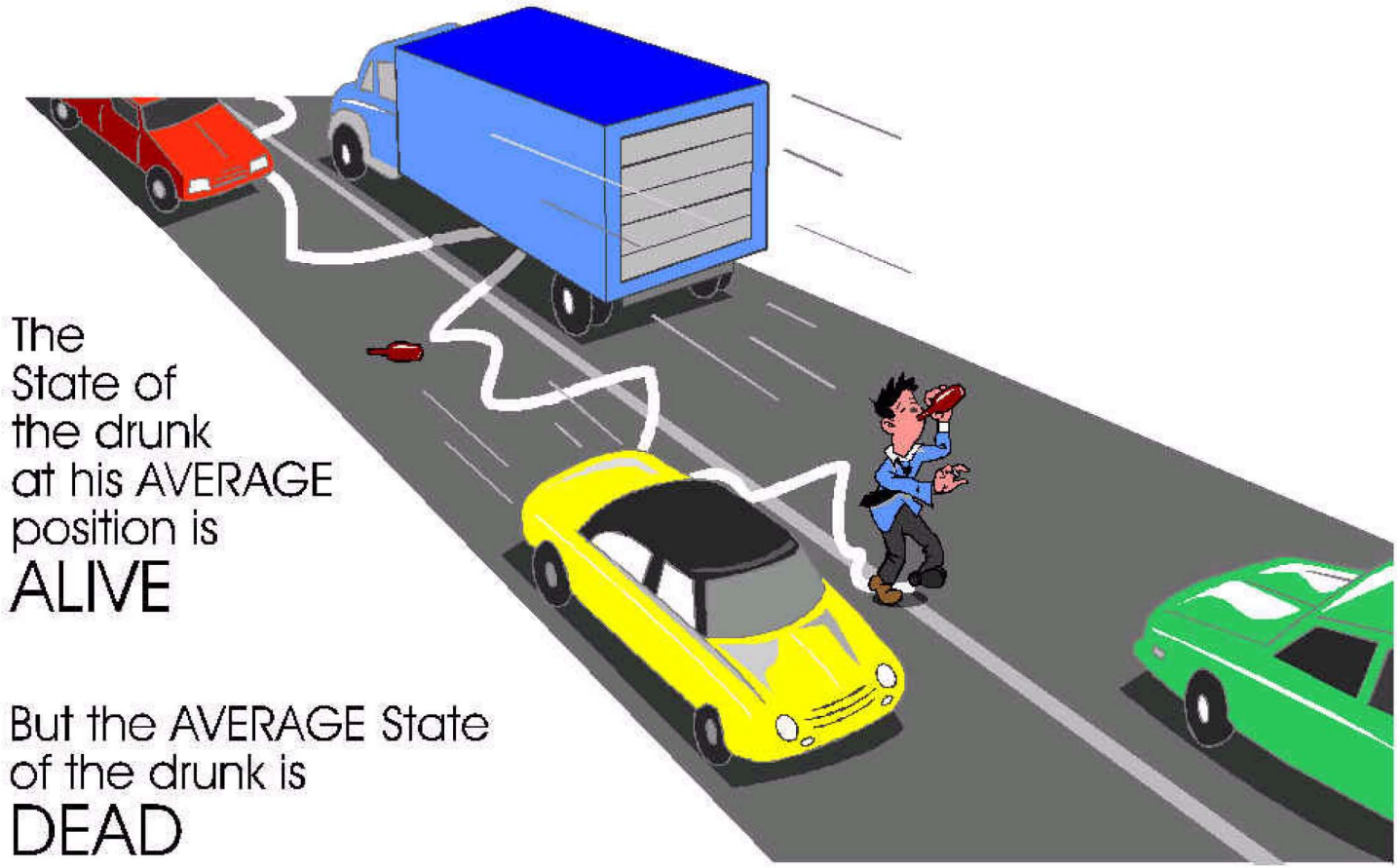
Questions



One Source...Many Solutions...One Purpose

Competitive Power College

PowerGen 2005

Selective Catalytic Reduction: From Planning to Operation

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Customers first. Energy that lasts.

One Source...Many Solutions...One Purpose

Presented By

Scott Straight, Director of Project Engineering – LG&E Energy

Joe Strickland, Senior Project Engineer – LG&E Energy

Joseph Langone, Vice President of Business Development, Babcock Power

Michael Kelly, Program Director – Babcock Power

Clayton Erickson, Director of Process Engineering – Babcock Power

Michael Jasinski, Process Engineer – Babcock Power

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Agenda

- Planning
- Capital Cost Estimating
- Design
- Construction, Commissioning, and Testing
- Operation
- Maintenance

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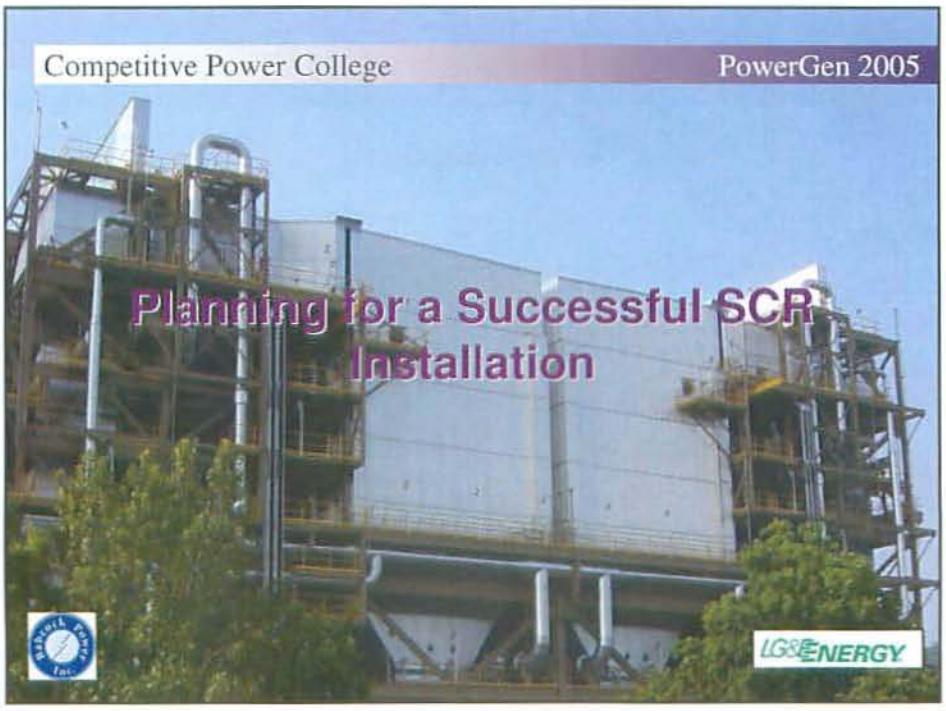

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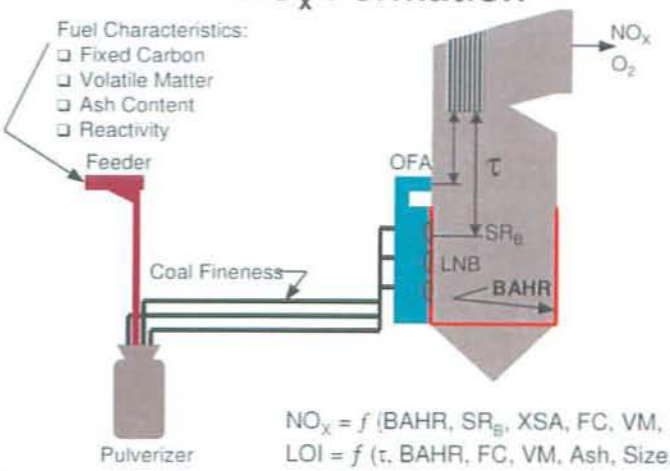
CAAA / Ozone Group

- Federal
  - CAIR (IAQR) other multipollutant initiatives
    - Utility MACT Hg and HCl
    - Phase II SIP Call
    - New Source Review
    - NSPS (Feb. 9, 2005)
  - 8-hour ozone NAAQS
    - PM 2.5, regional haze
    - Greenhouse gas
- State
  - Condensables
  - Multi-pollutant and mercury

State Regulatory Activity

NO_x Formation



$NO_x = f$ (BAHR, SR_B, XSA, FC, VM, N, LNB)

LOI = f (τ, BAHR, FC, VM, Ash, Size, NO_x)

SCR NO_x Outlet & Removal Efficiencies

- Reliability of firing system
- SCR system design
- Reliability of SCR system
  - Catalyst
  - Ammonia system
  - Controls
- Boiler dispatch and load characteristics
- Planned outage schedule

SCR NO_x Outlet & Removal Efficiencies

- Current SCR system design ranges
  - Inlet NO_x 0.32 to 2.3 lbs/MMBtu
  - Outlet NO_x 0.03 to 0.15 lbs/MMBtu
  - Removal efficiencies up to 92.5%
  - Ammonia slip < 2 ppm
- Current SCR system operation (2004 Ozone Data)
  - >20 units operating at > 90% removal
  - >20 units operating at < 0.05 lbs/MMBtu

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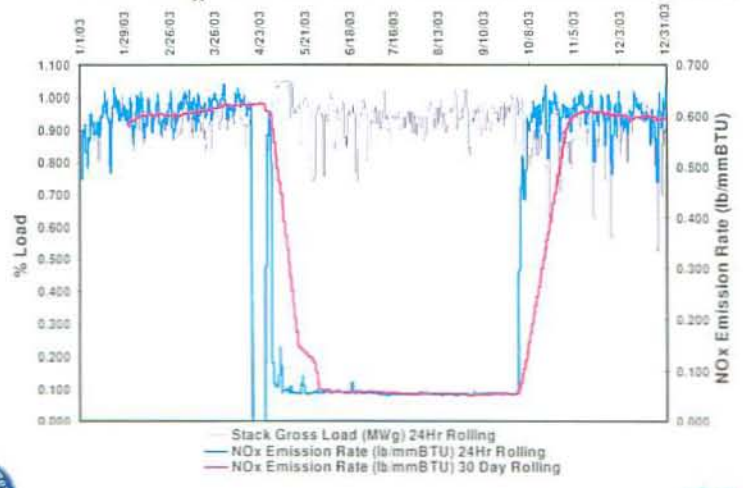
SCR NO_x Outlet & Removal Efficiencies



Baseline Testing

- Means to evaluate the boiler's pre-SCR operating conditions and to develop a mathematical model
- Boiler Tested at
  - Minimum Load
  - Intermediate Load
  - Maximum Load
    - Normal Excess Air
    - High Excess Air (+1.0%)
    - Clean Furnace
    - Dirty Furnace (Fouling effects on gas temperatures)

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Baseline Testing

- Local data collected throughout system
  - NO_x, O_2, & CO at the economizer outlet / future SCR inlet
  - O_2 profile for leakage calculation
  - Gas Pressure and Temperature Profiles
  - Fuel Samples
  - Ash Samples
    - Economizer Hoppers
    - Air Heater Hoppers
    - Precipitator Hoppers

Baseline Testing

- Control room data includes
  - Air and gas temperatures and pressures
  - Steam and water flows, temperatures, and pressures
  - SH/RH spray flows
  - Valve and damper positions
  - Burner and pulverizer data
  - Emissions and operating O_2
  - Fan and motor data

Baseline Testing - Evaluation

- Results yield
  - Flue Gas Flows (calculated by heat balance)
  - Draft loss data
  - Auxiliary equipment performance (ID fan capacity)
  - Air Heater performance
  - Air infiltration/leakage rates
  - Flue gas temperatures
  - Emissions
  - Boiler water and steam temperature profiles
  - Mathematical model for future operation

Baseline Testing - Evaluation

- Total Flue Gas Flow (Combustion + In-Leakage)
  - Ductwork sizing
  - Reactor Sizing
- Flue Gas Temperature vs Load
  - Minimum Operating Temperature & Load
  - Economizer Bypass Evaluation
- Boiler Conversion of SO_2 to SO_3
- I.D. Fan Operation
  - Evaluation of Impact of SCR on Existing Fans

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Ammonia System Selection

- Permit, site location, & location on site
- Neighborhood issues
- Delivery methods
  - Railcar
  - Truck
- Plant input
- Operation and maintenance considerations

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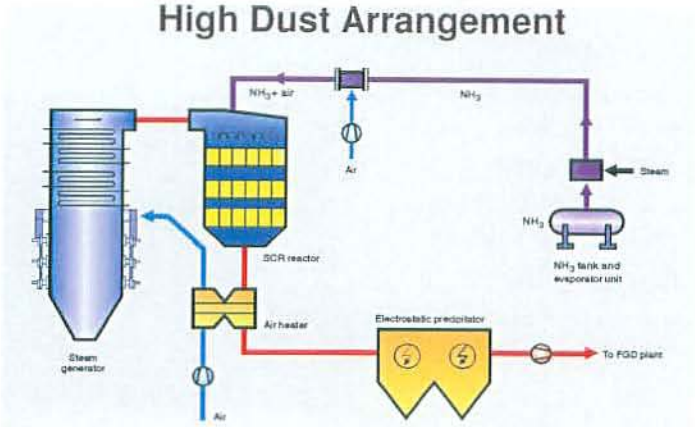
Ammonia Systems

- Anhydrous Ammonia
  - Hazardous chemical governed by codes
- Aqueous Ammonia
  - Concentration based codes, maybe changed in future
- Urea Based Ammonia
  - Safe storage, more equipment and complex

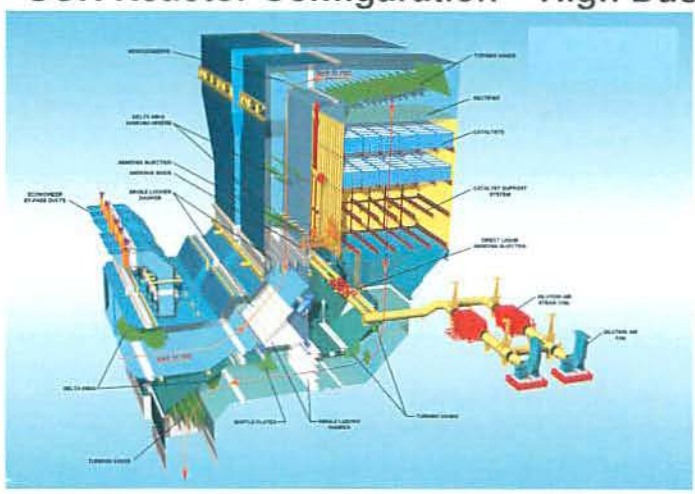
SCR Reactor Configuration

- High Dust
  - Typical of most U.S. installations
- Low Dust
  - Used for hot ESP installations
- Tail End
  - Site constraints limit access
- In Duct
  - Limited removal efficiency for coal
  - High removal efficiency for gas and oil

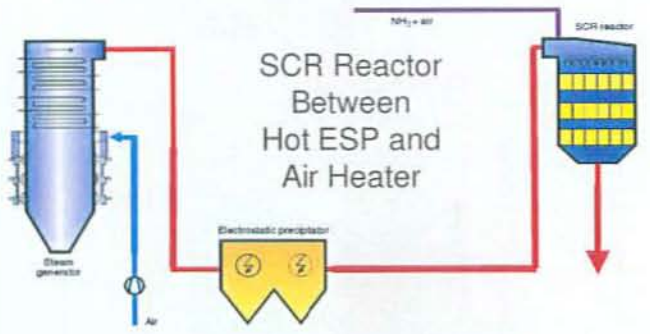
SCR Reactor Configuration
High Dust Arrangement



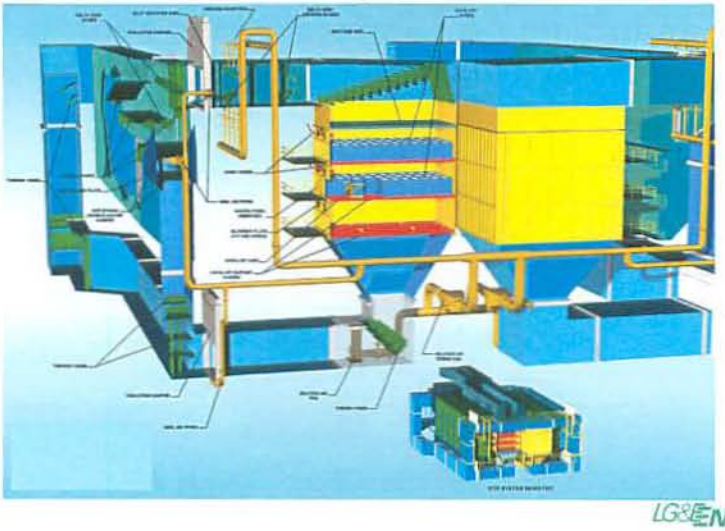
SCR Reactor Configuration – High Dust



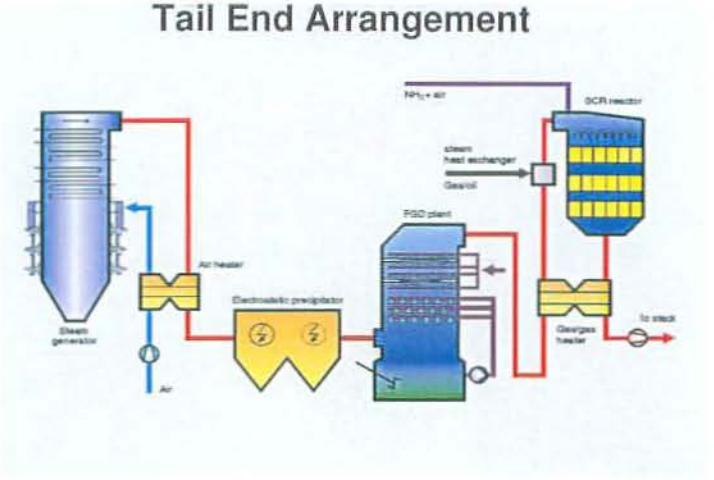
SCR Reactor Configuration
Low Dust Arrangement



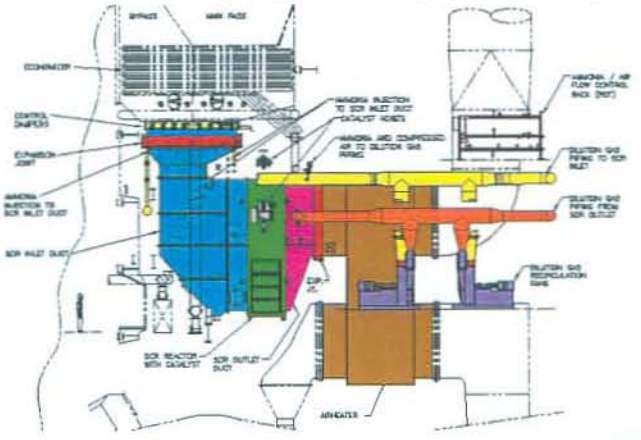
SCR Reactor Configuration – Low Dust



SCR Reactor Configuration
Tail End Arrangement



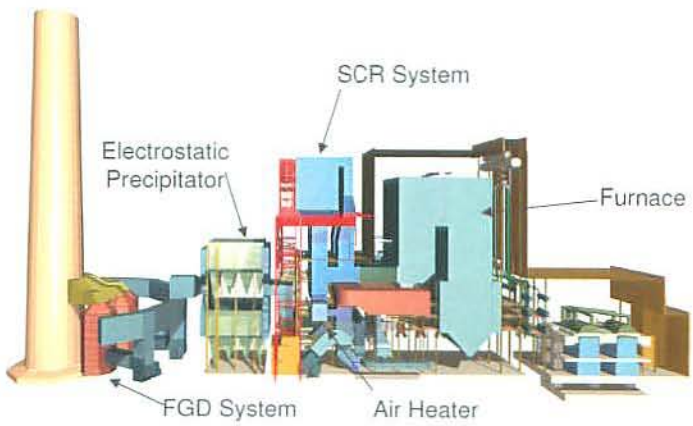
SCR Reactor Configuration
In Duct Arrangement (Gas Fired)



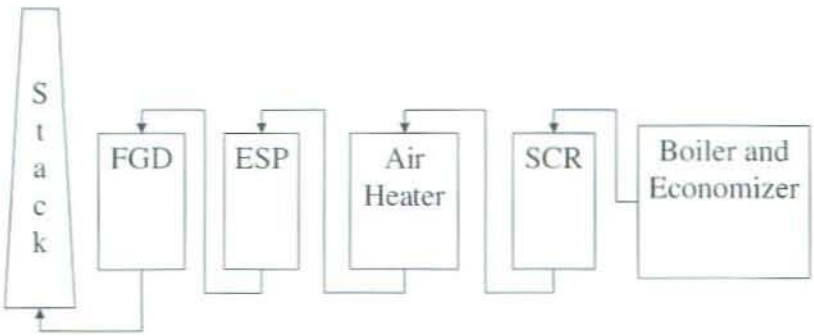
Current and Future Fuels

- Determine SCR impact on current fuel strategy
- Provide realistic fuels and ranges for design
- Avoid "picking and choosing" components for design fuel
- Consider other future plant retrofits
  - FGD
  - Firing systems
  - Fuel switches

SO_3 Balance – Flue Gas System



SO_3 Balance – Diagram



Parameters Affecting SO_3 Production and Capture in Furnace

- Slagging and fouling characteristics of coal
- Sulfur content of fuel
- Furnace type, wet bottom, cyclone or dry bottom
- Alkali content of fuel
- Furnace exit gas temperatures, equilibrium concentration and reaction kinetics
- Furnace gas retention times, kinetic formation rate
- Typical furnace conversion 0.1 to 1.8%

Parameters Affecting SO_2 to SO_3 Conversion In SCR System Catalyst

- SCR reactor operating temperature, strong function - increased inlet temperatures increases SO_3 conversion
- SO_2 inlet concentration, increased inlet SO_2 decreases SO_2 to SO_3 percent conversion rate
- NH_3 inlet concentrations and NH_3/NO_x ratios, increased NH_3 decreases SO_3 conversion
- O_2, H_2O and NO_x inlet concentrations, weak functions in coal fired operating ranges
- Typical catalyst conversion 0.8 to 3.0% (Full reactor)

Parameters Affecting SO_3 Capture in Air Heaters and Electrostatic Precipitator (ESP)

- Type of air heater, regenerative or tubular
- Operating flue gas and air temperatures
- Fly ash alkali content with respect to inlet SO_3 concentration
- Air leakage rates affecting gas temperatures
- Type of ESP, cold or hot
- Typical capture 25 to 70%

Parameters Affecting SO_3 Capture in FGD Systems

- Type of FGD system, wet, semi-dry, or dry
- Absorber configuration, counter or concurrent flow
- Absorber gas velocities and pressure loss
- Absorber inlet temperature
- Absorber operating parameters - L/G
- Typical capture 25 to 60%
  - Gaseous vs Aerosol Removal

Case Study Low Sulfur Bituminous Coal (< 1.5%) Plant Operating Parameters

- Furnace SO_2 to SO_3 conversion 0.33 to 1.8% (furnace type and ash alkali dependent)
- Regenerative air heater SO_3 capture rate 25 to 70% (temperature and ash alkali dependent)
- Tubular air heater SO_3 capture rate ~10%
- ESP SO_3 capture rate 0 to 20%

Case Study PRB Coal
Plant Operating Parameters

- Furnace SO_2 to SO_3 conversion 0.1%
- Air heater SO_3 capture rate ~0%
- ESP SO_3 capture rate ~0%
- SO_3 concentrations are within the resolution of the test measurement equipment

Case Study High Sulfur Coal (> 2.5%)
Plant Operating Parameters

- Furnace SO_2 to SO_3 conversion 0.8 to 1.25%
- Air heater SO_3 capture rate 15 to 35% (temperature dependent)
- ESP SO_3 capture rate 0 to 5%
- WFGD SO_3 capture rate 40 to 50%

SO_3 Balance – Potential Mitigations

- Furnace alkali addition, MgO injection or limestone addition to fuel.
- SCR catalyst temperature control, design or operating
- SCR catalyst selection
  - High vs low conversion
- Ammonia injection after air heater
- Alkali injection after air heater

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SCR Flue Gas System

- SCR Bypass
  - Inlet & Outlet Dampers
  - Able to isolate reactor during operation and startup
  - No catalyst deactivation during non-ozone season
- Startup Bypass
  - Dampers
  - Able to isolate during startup only
- No Bypass
  - No Dampers

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Low Load SCR Temperature Control

- Need to determine minimum SCR operating load
- Methods to provide adequate SCR temperature
  - Flue gas economizer bypass
  - Economizer water side bypass
  - Split economizer
  - Feed water heater pegging

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Major Outage Schedule Considerations

- Catalyst design life considerations
  - Current plant major outage cycle
  - Future plant major outage cycle
  - Desired margin/flexibility on outage cycle
- Increased outage work with catalyst addition/replacement
- Increased outage work with ammonia system, tank inspections, etc.

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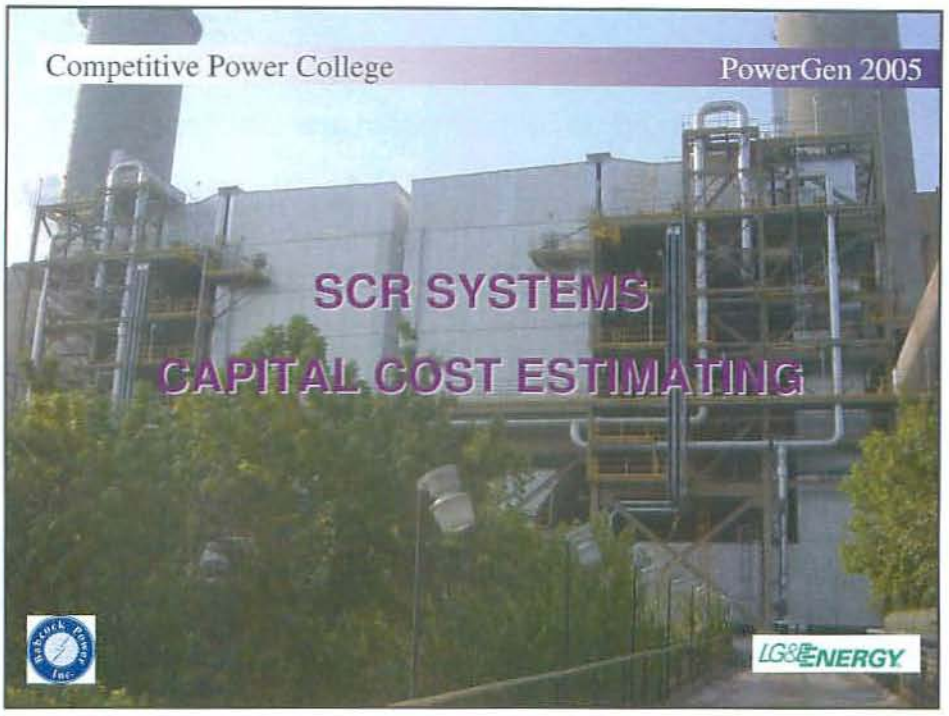

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EVERY PLANT IS UNIQUE!

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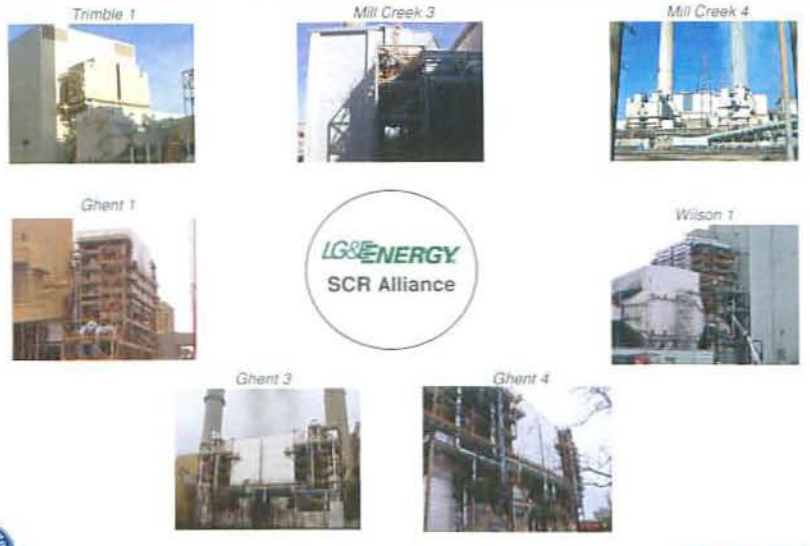

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Project Cost Factors

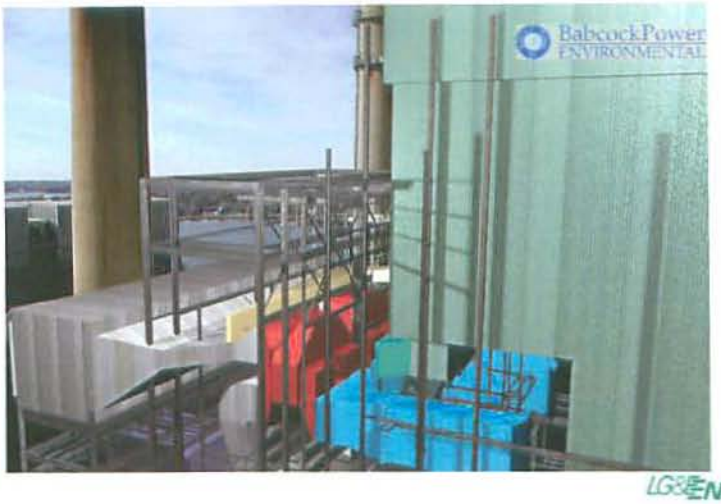
1. Labor Availability/Source/Productivity
2. Transportation Access
3. Site Congestion
4. Crane Lifting Systems
5. Number and Size of Units
6. Ammonia Systems
7. Auxiliary Equipment Modifications
   - Air Heaters
   - Electrostatic Precipitator
   - ID Fans
   - Boiler Modifications
8. SCR Design & Construction Experience

SCR Crane Systems




SCR Construction Sequence Model

SCR Construction Sequence Model (Movie)



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SCR Capital Cost Estimating Categories

1. Engineering
2. Piling & Foundations
3. Structural Steel
4. SCR Reactor, Ductwork & Expansion Joints
5. Isolation/Control Dampers
6. Catalyst
7. Catalyst Cleaning Systems
8. Ammonia Storage and Feed Systems
9. Dilution/Seal Air Systems
10. Electrical/Instrumentation & Controls

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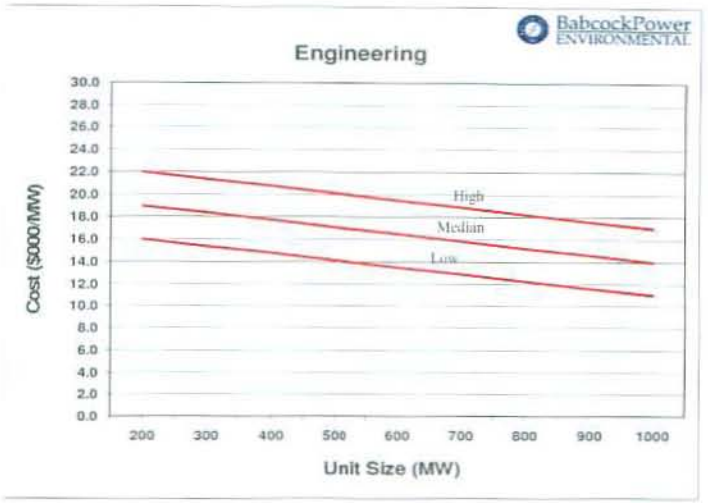

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Piling & Foundation Systems

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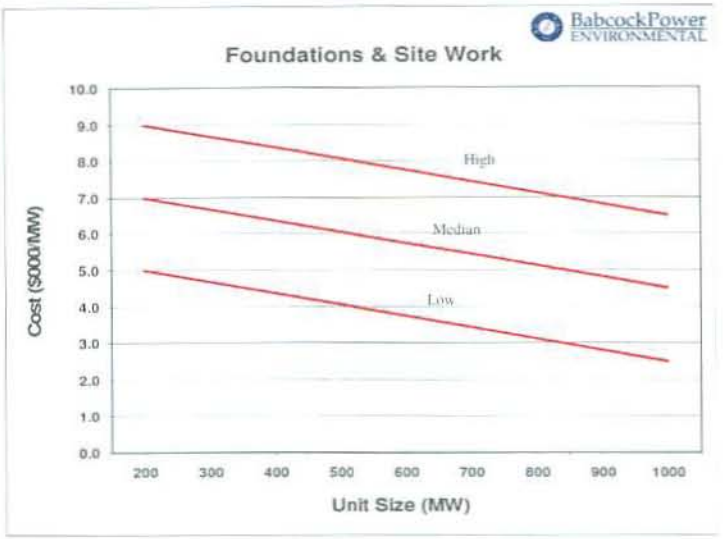

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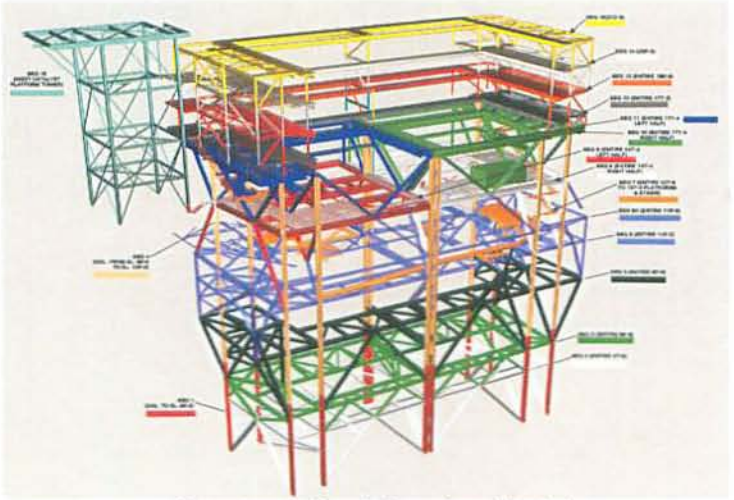

Structural Steel Framing Model

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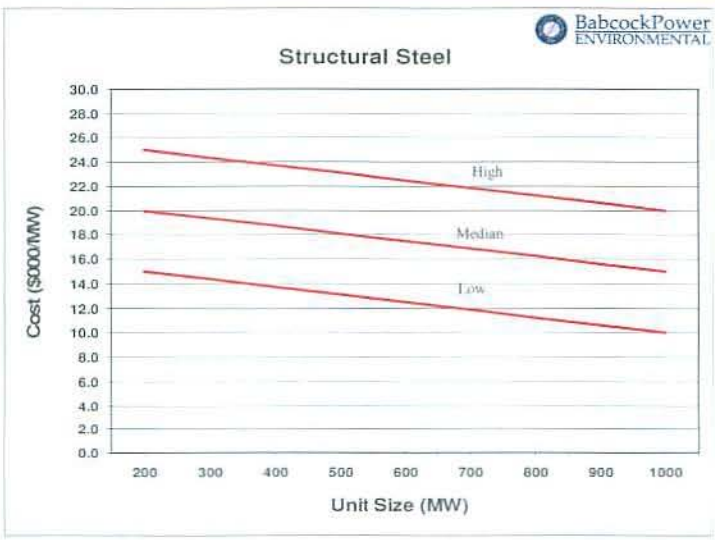
Structural Steel Systems



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SCR Reactor and Ductwork Systems

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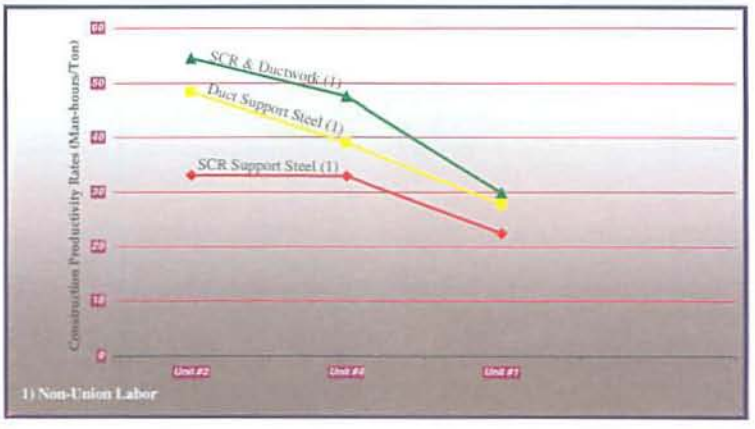
Construction Productivity Rates
Case Study Analysis



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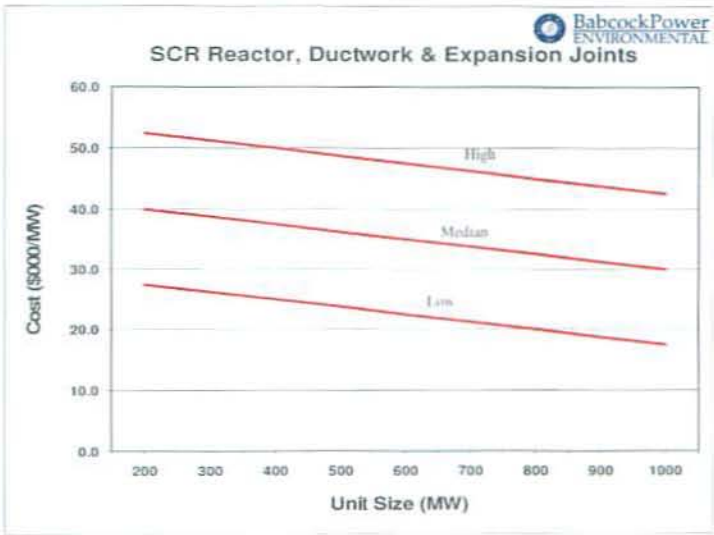

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Isolation/Control Damper Systems

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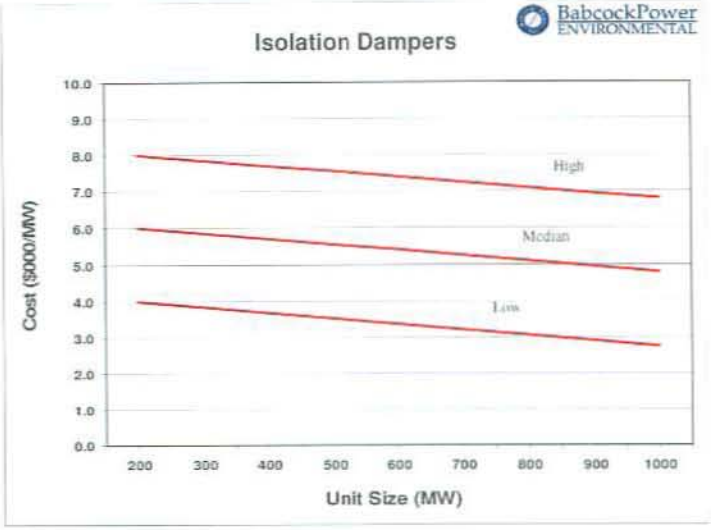

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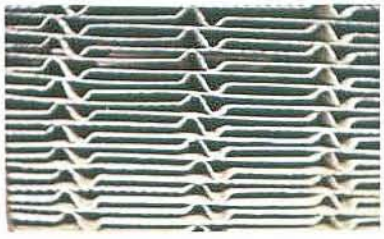
Catalyst Systems



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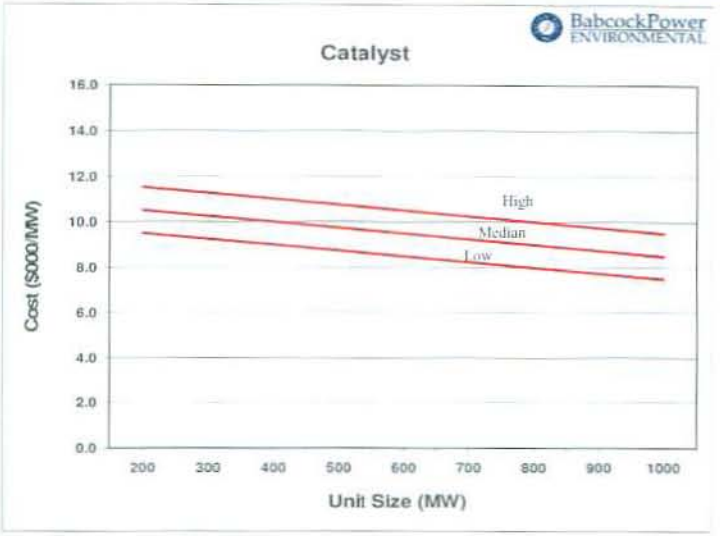

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Catalyst Cleaning Systems

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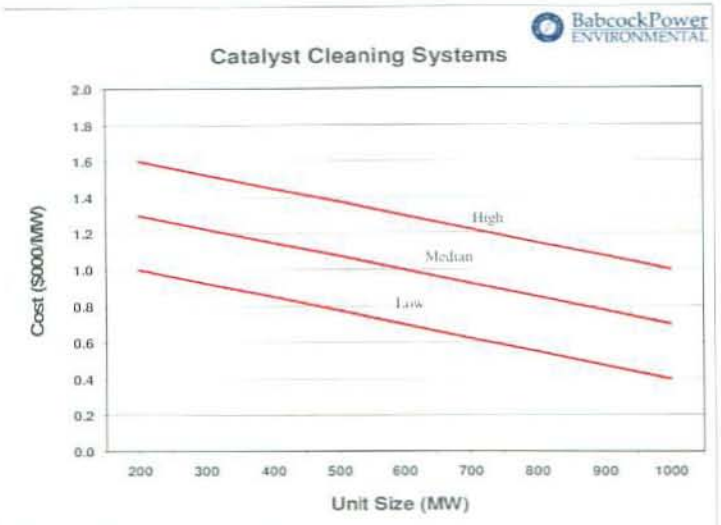

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Ammonia Systems




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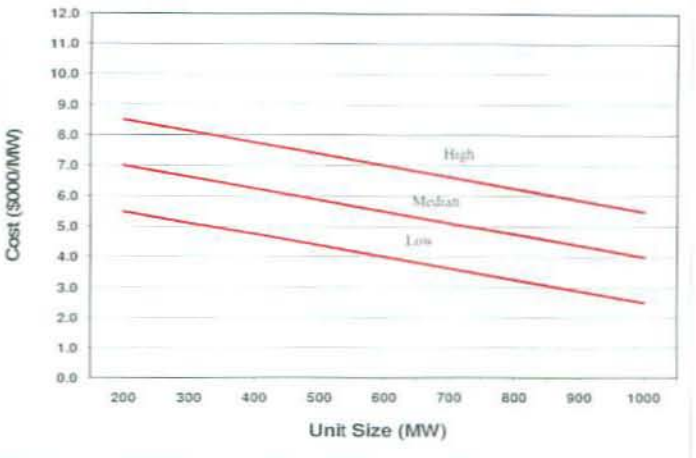
Ammonia Storage & Injection Systems



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Dilution/Seal Air Systems

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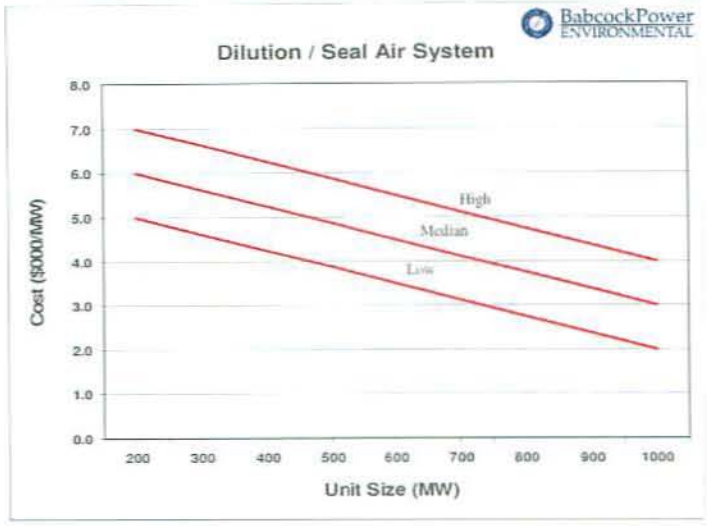

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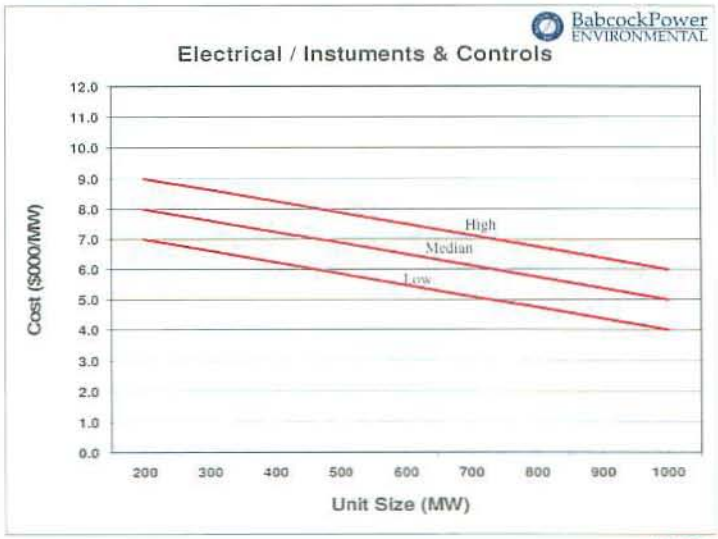

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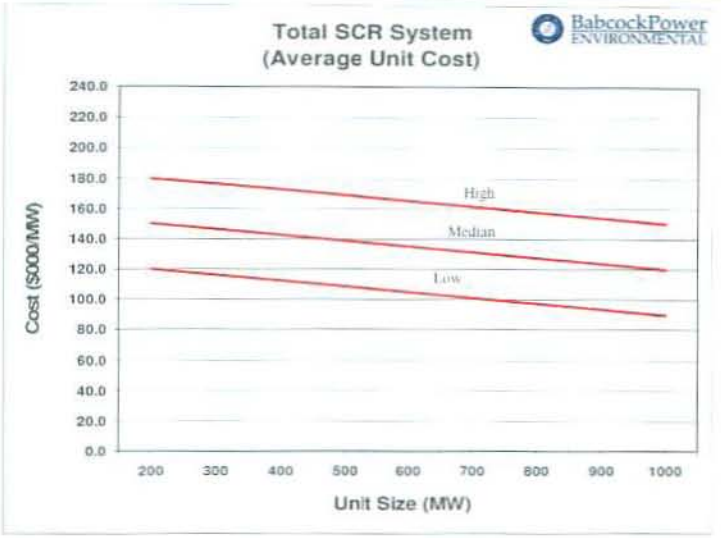

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Potential Additional Capital
Cost Modifications

1. ABS Air Heater Baskets and Cleaning Systems
2. Economizer Bypass System
3. Boiler Surface Modifications
4. Ash Collection System Modifications
5. Retrofit/New ID Fans & Drives
6. Balance of Plant Modifications

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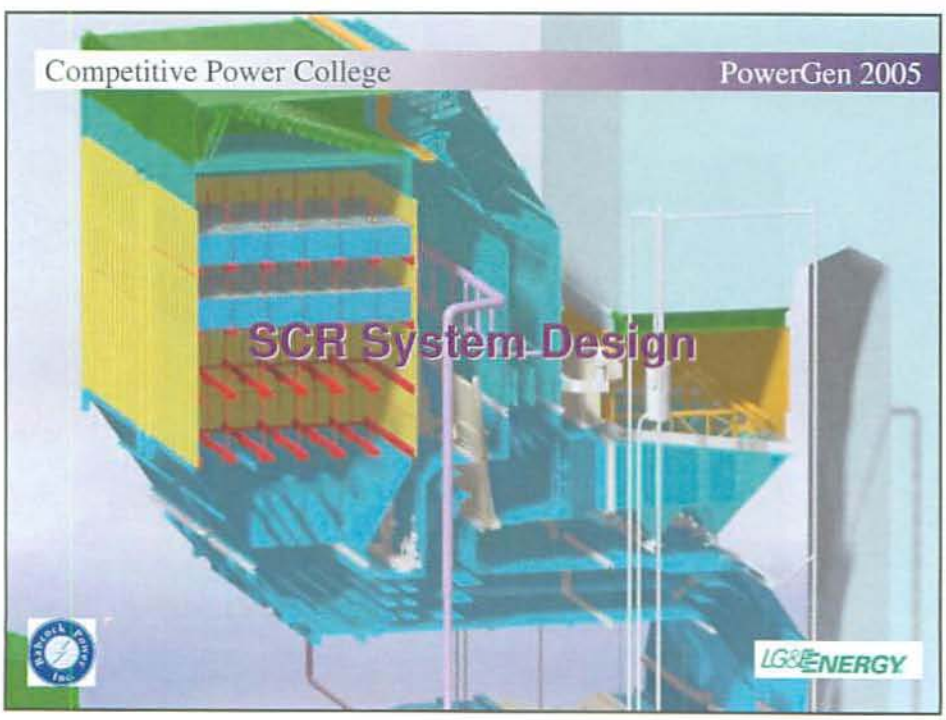
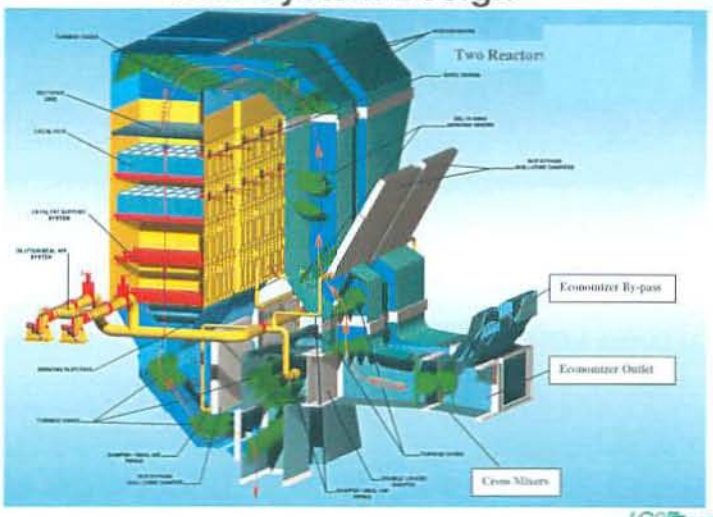
Every Plant is Unique!

Accurate Cost Estimating Requirements

1. Accurate Scope Definition – 25% Engineering Completed
2. Development of Detail Project Plan
   - Construction Equipment
   - Construction Sequence & Outages
   - Detailed Integrated Project Schedule
3. Proven Cost Estimating Database
4. Experienced Engineering & Construction Team



SCR System Design



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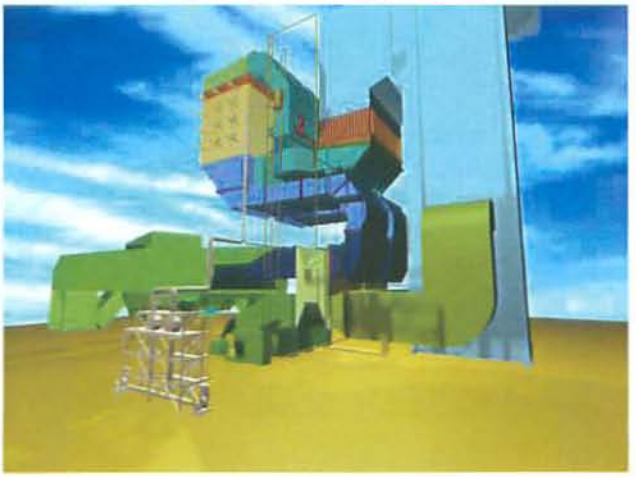
SCR System Design (Movie)



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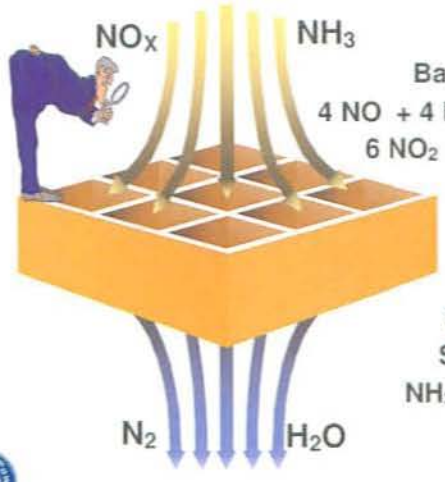
Basic SCR Chemistry



Basic reaction equations

$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$

$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$

Typical coal flue gas
95% NO & 5% NO_2

Undesirable side reactions

$SO_2 + 1/2\ O_2 \rightarrow SO_3$

$NH_3 + SO_3 + H_2O \rightarrow NH_4HSO_4$

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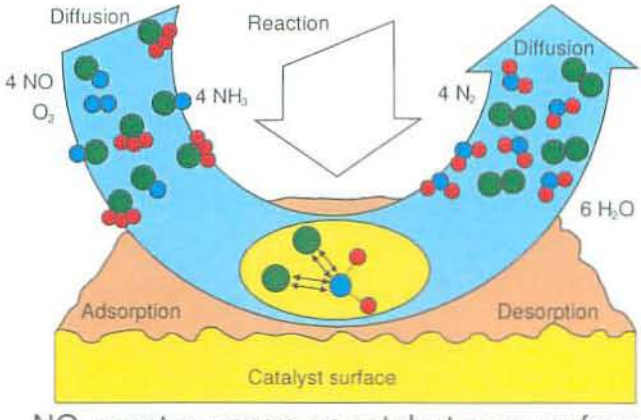
Basic SCR Chemistry



NO_x reactor occurs on catalyst pore surface

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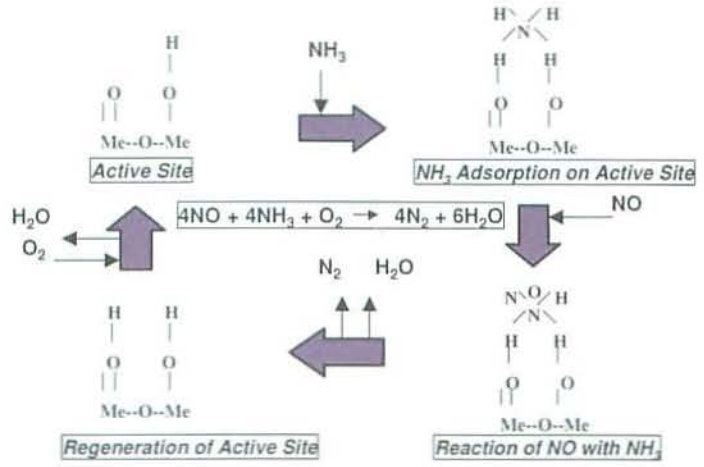
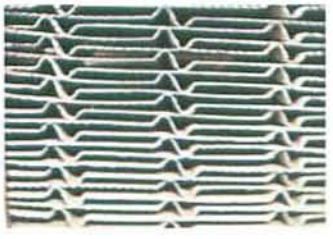
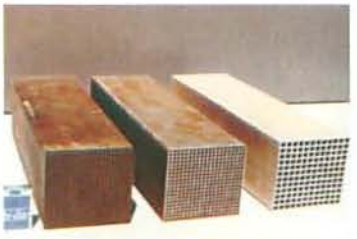
Basic SCR Chemistry



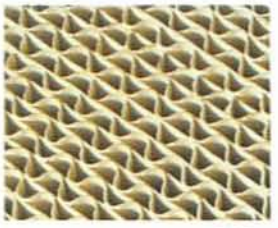
Catalyst - Types

- Honeycomb





- Plate
- Corrugated



Catalyst Design

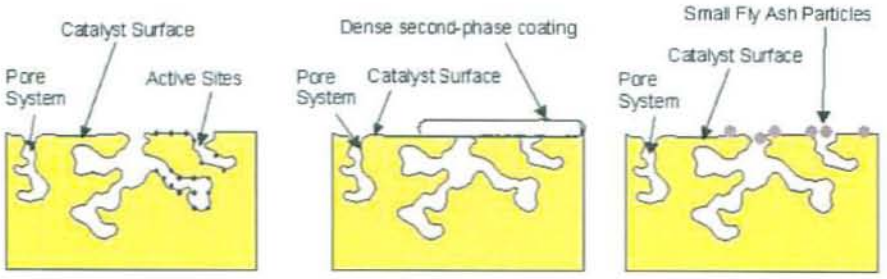
- Fuel Considerations
  - Sulfur content
    - Ammonium salts
    - Minimum continuous operating temperature
  - Ash loading
  - Arsenic in coal
  - CaO in flyash
- Ammonia Slip
- Catalyst Life
- SO_2 to SO_3 Conversion

Catalyst – Deactivation

Poisoning:
Deactivation of active catalyst sites by chemical attack

Masking:
Macroscopic blockage of catalyst surface by dense second-phase coating

Plugging:
Microscopic blockage of catalyst pore system by small fly ash particles



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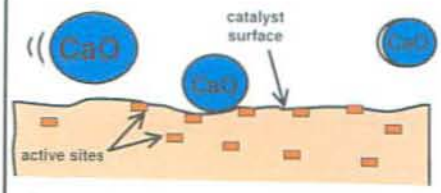
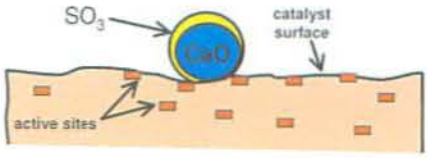
Catalyst – CaO Deactivation

Step 1
- CaO is caught on the catalyst surface
- Process is dependent on availability and adhesion of CaO



•Rate controlling process for deactivation
•Very slow concentration changes (~10^4 hours)

Step 2
- SO_3 bonding & diffusion
- Process is function of mass transfer and concentration



•Fast reaction time (~10^1 hours)

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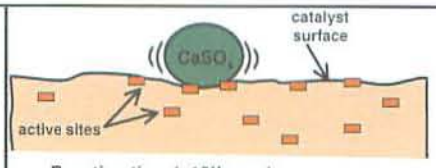
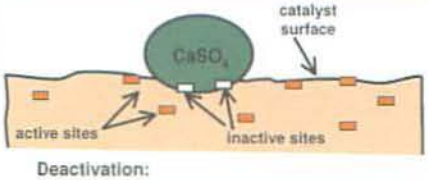
Catalyst – CaO Deactivation

Step 3
- Diffusion and expansion CaO + $SO_3 \longrightarrow CaSO_4$
- Reaction is a function of diffusion rate and SO_3 concentration



•Reaction time (~10^1hours)
•Particle expansion of 14%

Step 4
- Deactivation is a function of CaO loading over time



Deactivation:
NH_3 & NOx can't reach masked active sites

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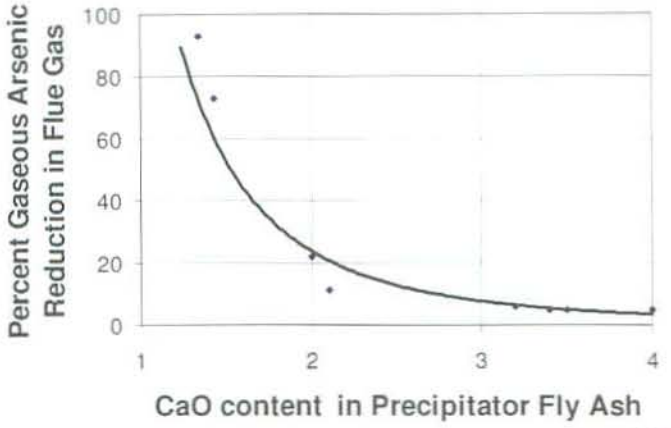
Catalyst – Arsenic Control



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Catalyst – Minimum Continuous Operating Temperature (T_{mcot})

- Minimum operating temperature for SCR without formation of ammonium salts
- High partial pressure in catalyst pores
  - Dew point in pores >> Dew point in duct
- $T_{mcot} = f(SO_3, NH_3, H_2O)$
- Excess of NH_3 and H_2O at catalyst inlet
  - SO_3 from boiler limiting factor
  - ↑S in Fuel, ↑T_{mcot}

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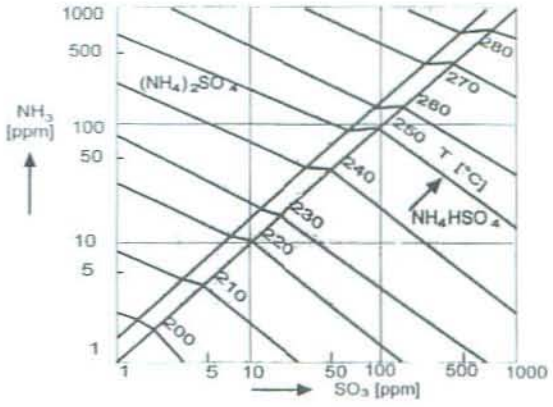
Catalyst – Minimum Continuous Operating Temperature (T_{mcot})



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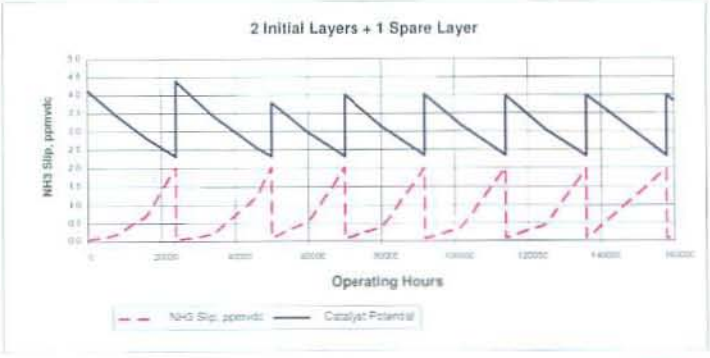
Catalyst – End of Life

- Period of time in which the catalyst will reach its designed slip



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Catalyst – Ammonia Slip

- Unreacted ammonia exiting SCR reactor
- Increases throughout life to design
- Need to control for ammonia salt pluggage
  - European experience 5 ppm slip
  - U.S. experience 2 ppm slip
- Function of NH_3/NO_x distribution
- Typical guarantee

Catalyst – Cleaning

- Steam Sootblowers
  - Requires controlled steam quality, dry steam
  - Rake type sootblower
  - Required for high ash concentration (> 20 g/Nm^3)
- Sonic Horns
  - Compressed air requirements typical of service air
  - Low air quantities required
  - Continuous operation
  - U.S. application and popularity increasing

Catalyst – Typical Mixing / Flue Gas Conditions

- Temperature ± 15 °C (27 °F)
- Velocity ± 20%
- Flow Direction ± 10 °
- Inlet NO_x 5% rms from the mean
- NH_3/NO_x 5% rms from the mean

Catalyst and Reactor Sizing

- Catalyst inlet velocity 12 to 14 ft/s
- Reactor size and structure to accept any catalyst type
- Spare catalyst layers as required per catalyst management
- Total reactor catalyst volume capacity for current and future fuels

Catalyst Design Process

1) Design Input
2) Performance Requirements
3) Pitch Selection & Deactivation
4) Formulation
5) Final Design

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Catalyst Design Input

- Flue gas flowrate
- Inlet NO_x
- Flue gas composition
- Current and future fuel constituents
- Reactor cross section and number of layers
- SCR configuration
- Ash Loading
  - Properties
  - Large Particle Ash

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Catalyst Performance Requirements

- NO_x removal efficiency
- Ammonia slip at end of life
- Pressure drop
- Required SO_2 to SO_3 oxidation
- Catalyst life for initial volume
- Mixing performance

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Catalyst Pitch Selection / Deactivation

- Pitch Selection
  - SCR configuration
  - Fuel characteristics
  - Ash characteristics
- Deactivation
  - SCR configuration
  - Fuel characteristics
  - Ash characteristics
  - Catalyst Life

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Catalyst Formulation

- Determined by catalyst vendor based on experience
- Major influence by
  - SCR configuration
  - Required SO_2 oxidation
  - Temperature range

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Catalyst Final Design

- Catalyst volume
- Catalyst life as function of fuel
- Catalyst management plan
- Performance correction curves

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Catalyst "Co-benefit" – Mercury Oxidation

- Mercury Speciation in Flue Gas
  - Elemental Mercury (Hg^0)
  - Oxidized Mercury (Hg^{2+})
  - Particulate Mercury (Hg_p)
- Mercury Removal in Flue Gas Desulfurization (FGD) Processes
  - Wet FGD removal
    - High removal of Hg^{2+} and Hg_p
    - No removal of Hg^0
  - Dry FGD removal
    - High removal of Hg^{2+} and Hg_p
    - High removal of Hg^0 for bituminous and no removal for sub-bituminous coals
- Catalyst Typically Oxidizes Hg^0 to Hg^{2+}

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Catalyst "Co-benefit" – Mercury Oxidation

- Mercury Oxidation Dependent on Multiple Factors
  - Fuel Composition (Primarily Cl)
  - Residence time or Space velocity
  - Flue Gas Temperature (Secondary)
- No Apparent Affect on Oxidation with Catalyst Variables
  - Formulation
  - Type
  - Age

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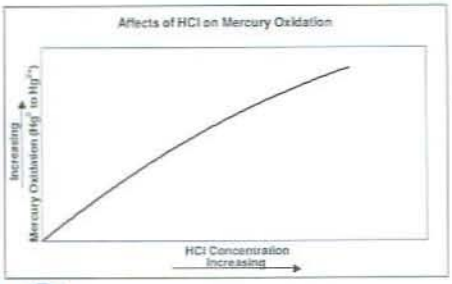
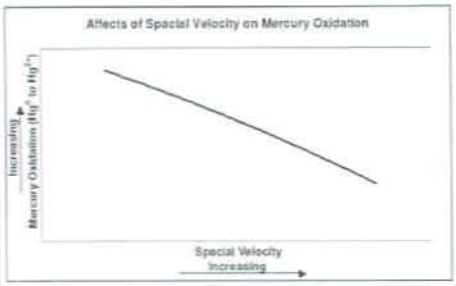
Catalyst "Co-benefit" – Mercury Oxidation

- Temperature Affects – Curve Shift





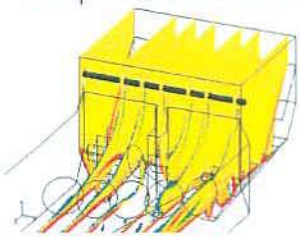
Large Particle Ash (LPA)

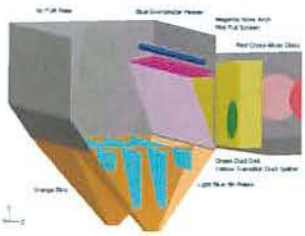
- LPA Properties
  - Size >4.0 mm
  - Density 0.7 to 1.25 g/cc
  - Sphericity 0.7 to 0.99
  - Coefficient of Restitution 0.15 to 0.2

- Screen Design Important
- Pluggage
- Erosion

LPA Screen Design

- Design and Modeling
  - CFD Modeling
  - Industry Coated Screens
  - Experience From Past





- Soot Blowers
- Low Velocity
- Low Pressure Loss

Lay-up Air System Design

- Used for full SCR bypass units
- Operates during non-Ozone season only
- Dedicated or dual function as ammonia dilution air
- During non-Ozone season maintains SCR reactor free of flue gas and above freezing
- Heat source steam or electric
- Typically 2 x 100% systems provided

Ductwork Sizing - Velocity

- Flue gas velocity
  - Typically 3600 fpm
  - Limited to 4200 fpm for erosion (High dust)
  - Minimum for LPA dropout
- Ash loading
  - 90 lbs/ft^2 on surfaces < 45°
- NFPA
  - 85.04 design pressure and temperature requirements

Ammonia System – Required Flow

- How is NO_x expressed for calculation?
  - NO
  - NO_2
  - NO & NO_2
- Proper injection and storage system sizing

Ammonia System – Required Flow

- NO_x expressed on NO only basis

$$m_{NH3} = MW_{NH3} \cdot \frac{m_{NOx} \cdot \eta}{MW_{NO2}} \cdot (2 - \%NO)$$

Example:

$$m_{NOx} = 10{,}000\ lbs/hr$$

$$\eta_{NOx} = 90\%\ of\ inlet\ NO_X$$

$$m_{NH3} = 17.03 \cdot \frac{10{,}000 \cdot 0.9}{46.01} \cdot (2 - 1)$$

$$m_{NH3} = 3{,}331\ lbs/hr$$

Ammonia System – Required Flow

- NO_x expressed on NO_2 basis (Federal Registrar)

$$m_{NH3} = MW_{NH3} \cdot \frac{m_{NOx} \cdot \eta}{MW_{NO2}} \cdot (2 - \%NO)$$

Example:

$$m_{NOx} = 10{,}000\ lbs/hr$$

$$\eta_{NOx} = 90\%\ of\ inlet\ NO_X$$

$$m_{NH3} = 17.03 \cdot \frac{10{,}000 \cdot 0.9}{46.01} \cdot (2 - 0)$$

$$m_{NH3} = 6{,}662\ lbs/hr$$

Ammonia System – Required Flow

- NO_x expressed as 95% NO & 5% NO_2

$$\dot{m}_{NH3} = MW_{NH3} \cdot \frac{\dot{m}_{NOx} \cdot \eta}{MW_{NO2}} \cdot (2 - \%NO)$$

Example:

$$\dot{m}_{NOx} = 10{,}000\ lbs/hr$$

$$\eta_{NOx} = 90\%\ of\ inlet\ NO_x$$

$$\dot{m}_{NH3} = 17.03 \cdot \frac{10{,}000 \cdot 0.9}{46.01} \cdot (2 - 0.95)$$

$$\dot{m}_{NH3} = 3498\ lbs/hr$$

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Ammonia System – Required Flow

- Different ammonia flows depending on basis
  - NO Basis = 3,331 lbs/hr
  - NO_2 Basis = 6,662 lbs/hr
  - NO & NO_2 Basis = 3,498 lbs/hr
- Correct Design for ammonia system by NO and NO_2 basis

Ammonia System – Safety Codes & Standards

- 3 Levels of alarm and detection
  - 35 ppm (Lights): Threshold Limit Value – Short Term Exposure Limit (TLV-STEL) by the American Congress of Governmental Industrial Hygenists (ACGIH)
  - 50 ppm (Lights & Horns): OSHA 8 hour exposure limit.
  - 300 ppm (Lights, Horns, & E-Stop): Immediately Dangerous to Life or Health (IDLH) limit from the National Institute for Occupational Safety and Health (NIOSH) and OSHA

Ammonia System – E-Stop

E-STOP CAUSE \ E-STOP RESULT	CLOSE ALL TRUCK UNLOADING STATION VALVES	CLOSE ALL TANK LIQUID & VAPOR FILL VALVES	CLOSE ALL TANK OUTLET & RETURN PROCESS SUPPLY VALVES	STOP PUMPS	CLOSE PUMP SKID ISOLATION VALVE	CLOSE INJECTION SKID ISOLATION VALVE	CLOSE SCR INJECTION CONTROL VALVES
TRUCK UNLOADING SKID STOP PB	X	X					
TRUCK UNLOADING SKID NH_3 LEAK	X	X					
TANK E-STOP PB	X	X	X	X	X	X	X
PUMP E-STOP PB	X	X	X	X	X	X	X
PUMP LEAK DETECTION	X	X	X	X	X	X	X
TANK LEAK DETECTION	X	X	X	X	X	X	X
TANK LEVEL HIGH	X	X	X	X	X	X	X
TANK PRESSURE HIGH	X	X	X	X	X	X	X
INJECTION SKID E-STOP PB						X	X
INJECTION SKID NH_3 LEAK DETECTION						X	X
FLOW CONTROL INJECTION VALVE LEAK DETECTION						X	X
MAIN CONTROL ROOM E-STOP DISPLAY E-STOP PB	X	X	X	X	X	X	X
AMMONIA HANDLING E-STOP DISPLAY E-STOP PB	X	X	X	X	X	X	X

Ammonia System – References

- American National Standards Institute (ANSI)
- Compressed Gas Association (CGA)
- Occupational Safety and Health Administration (OSHA)
- National Fire Protection Association (NFPA)
- Ammonia Data Book, International Institute of Ammonia Refrigeration, 1992

Ammonia Injection Systems

- **Anhydrous**
  - Vaporizers
  - Direct Injection
  - Dilution air, 5% by Volume
- **Aqueous**
  - Vaporizers
  - Direct Injection
  - Dilution air, 5% by Volume
- **Urea**
  - Direct Injection
  - Dilution air, 5% by Volume

Ammonia System – Anhydrous

- 99.5% NH_3, 0.5% H_2O
- Method of vaporization
  - Flooded vaporizer with storage tank
  - Level controlled vaporizer
  - Direct injection
- Dilution air
  - 5% ammonia by volume (lower explosive limit 15%)
  - Typically 175 to 300 °F at duct injection location

Ammonia System – Anhydrous Codes

- OSHA 29 CFR 1910.111, Storage and Handling of Anhydrous Ammonia
- ANSI/CGA K61.1, Safety Requirements for the Storage and Handling of Anhydrous Ammonia
- ASME B31.3, Process Piping

Ammonia System – Anhydrous Equipment Selection

- Storage Tanks
  - -28 °F to site maximum design temperature
  - 250 psig design pressure minimum
  - Code ASME Section VIII Vessel
  - Excess flow valves on all nozzles
  - Two methods of level indication
- Transfer pumps
  - Seal less pump design
    - Magnetic drive
    - Canned pump
  - Suction pipe design
  - Recirculation vs injection rate

Ammonia System – Anhydrous Equipment Selection

- Piping / Valves
  - No copper, brass, or galvanized steel
  - Conforming to AMSE B31.3, Process Piping
  - Minimum number of threaded connections
  - Hydrostatic relief required on all isolatable sections
  - Leak / Pressure tests of system prior to service
  - All instrumentation suitable for anhydrous ammonia

Ammonia System – Anhydrous Equipment Selection

- Truck / Railcar Unloading
  - Snappy Joes & Breakaways to protect ammonia equipment
  - DOT Regulations to be followed
  - Railroad unloading procedures per ammonia / railroad supplier
  - Truck unloading procedures per ammonia / truck supplier

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Ammonia System – Aqueous

- 3 Common concentrations
  - 9% Ammonia
  - 19% Ammonia
  - 29% Ammonia
- No definitive codes or standards
- Sound engineering practices need to be applied

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Ammonia System – Aqueous Equipment Selection

- Storage Tanks
  - ASME Section VIII
  - API 610
- Pumps same as anhydrous
- Pipes and valves
  - No definitive codes or standards
  - Typical ASME B31.1 acceptable
- Unloading by truck only

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Ammonia System – Urea

- Multiple conversion technologies available
- Typically delivered in dry or liquid form
- Best stored on site as liquid
- No definitive codes or standards
- Good engineering practice need to be applied
- Heat tracing critical

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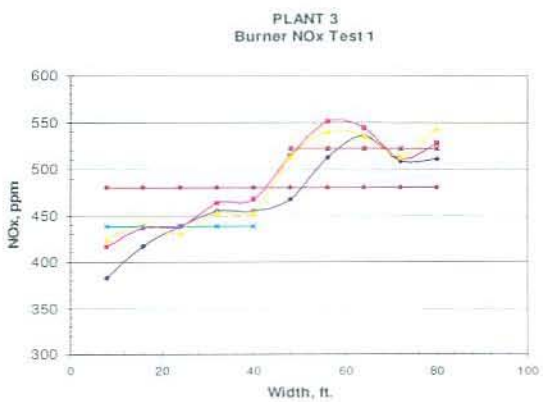
Mixing System Design

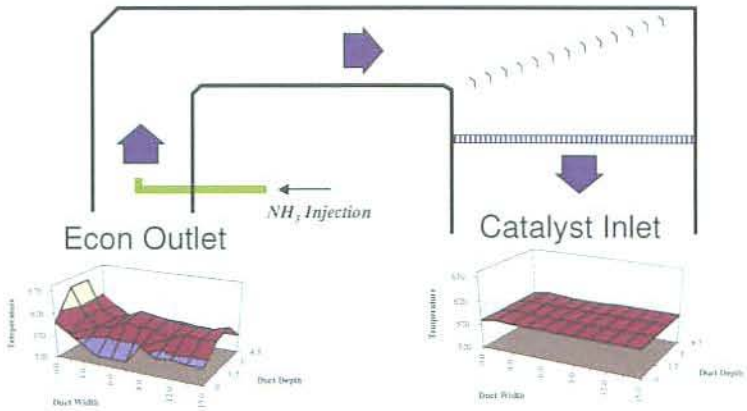
- Account for firing system variations
- Account for draft system variations
- Provide catalyst required mixing performance
- Provide downstream equipment zero impact from pre-retrofit
- Minimize draft loss
- Minimize undesired ash layout

Firing and Draft System Variations



- Inlet variations of flue gas composition
- Load and burner group dependent
- Mix prior to ammonia injection

Ammonia Injection & Flue Gas Mixing

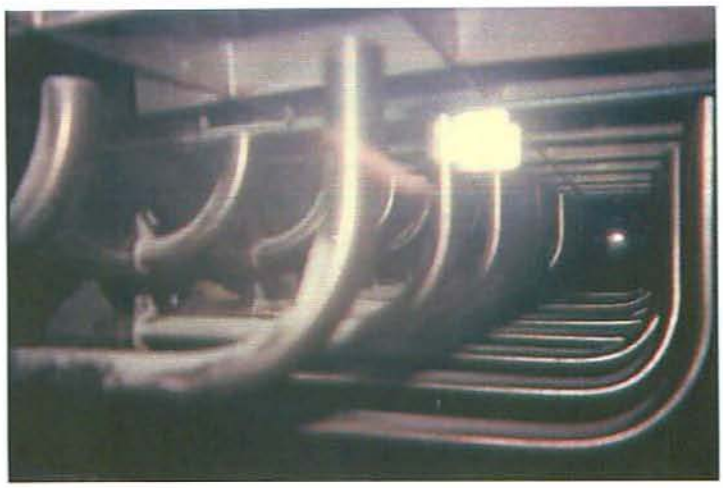


Ammonia Injection Grid – No Mixers

Static Mixers – Small Vortices

Static Mixers – Small Vortices

Static Mixer Ammonia Injection Grid



Static Mixers – Large Vortices

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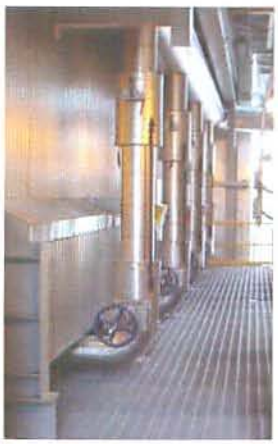
Large Vortices Ammonia Injection



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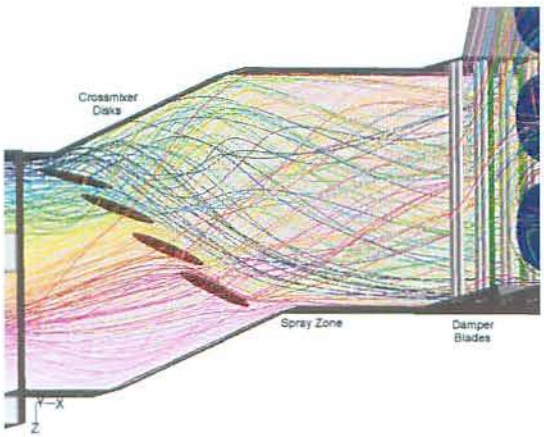
Mixing Prior to Ammonia Injection

Gas Flow from Boiler



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Flow Modeling - Goals

- Minimize Ductwork Pressure Drop
- Assure Mixing and Flow Distribution
- Study and Minimize Potential Ash Layout Areas
- Optimize SCR as Complete System
- Required on all Projects due to Changing Configurations
- Special Cases – Single Model for Two Units

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Flow Modeling – Parameters

- Number of dimensionless parameters to ensure results in model match full scale
  - Geometric Similarity
  - Velocity Levels
  - Velocity Head
  - Difference in Fluid Properties

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Flow Modeling – Parameters

- Reynolds-Number
  - Ratio of the inertia forces to friction forces

$$\mathrm{Re} = \frac{v \cdot b}{\nu}$$

v = velocity, b = characteristic length, ν = kinematic viscosity

  - Generally not possible to perform model at full scale Re but in power plant systems friction forces << inertia forces
  - Modeling successful when Re is in the turbulent range

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Flow Modeling – Parameters

- Euler Number
  - Relation between pressure forces and inertia forces

$$Eu = \frac{\Delta P}{\rho \cdot v^2}$$

ρ = density, ΔP = pressure difference, v = velocity

  - Basis for converting model ΔP to full-scale ΔP
  - Correct geometric similarity must be met for accurate results

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Flow Modeling – Parameters

- Barth Number
  - Relation between drag forces and inertia forces of a particle in gas

$$Ba = c_D \cdot \frac{\rho_{gas}}{\rho_m} \cdot \frac{l}{d_m}$$

c_D = drag coefficient, ρ_{gas} = density gas, ρ_m = density particle, l = characteristic length of duct, d_m = diameter of particle

  - Model test independent of absolute value of velocity but must be greater than minimum Froude number.
  - Froude number (ie gravity) can be ignored at higher velocities

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Flow Modeling – Boundary Conditions

- Economizer exit distributions
  - Defined from baseline testing
  - Based on past unit experience
  - At a minimum ± 20%
    - Velocity
    - Gas Composition
  - Temperature ± 50 °F
- Air heater inlet distributions per OEM's recommendations

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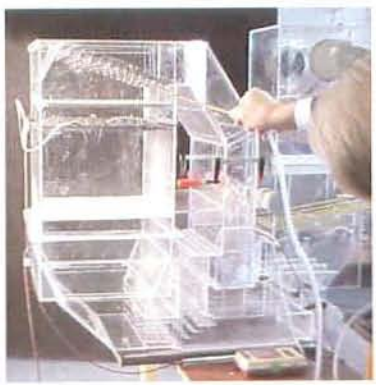
Flow Modeling – Model Scales

- Gas mixing and design 1:40 to 1:12
  - Larger scale (smaller model) allows for faster design changes
  - Experience with transition between larger scale to smaller scale to full scale
- Dust layout 1:16 to 1:12
  - Necessary to satisfy the Barth number

SCR Flow Models



SCR Availability

- Defined by IEEE Standard 762

$$Availability = \frac{Available\ Hours}{Period\ Hours}$$

- SCR system "able" to operate if called on
- SCR system meeting outlet emissions or removal percentage
- Averaging period: hourly, daily, monthly?

SCR Availability – Previous Work

- 90% NO_x Removal Elusive
- 0.07 lbs/Mbtu Least NO_x Outlet for Dry-Bottom Retrofit
- Difficulty Achieving Short Term (24 hour or less) Average Times
- Low NO_x Outlet "Targets" Offer Small, Unforgiving Margins
- "Overcontrol" The Entire Ozone Season To Compensate For Process Shortfalls

SCR Availability – Data Source

- Data downloaded from
  - Acid Rain/OTC Program Hourly Emission Data
  - www.epa.gov/airmarkets/emissions/raw
- Analysis period year 2004
- Ozone season June 1st to September 30th
  - Some states had one month start delay
- Single stack only data, common stacks removed

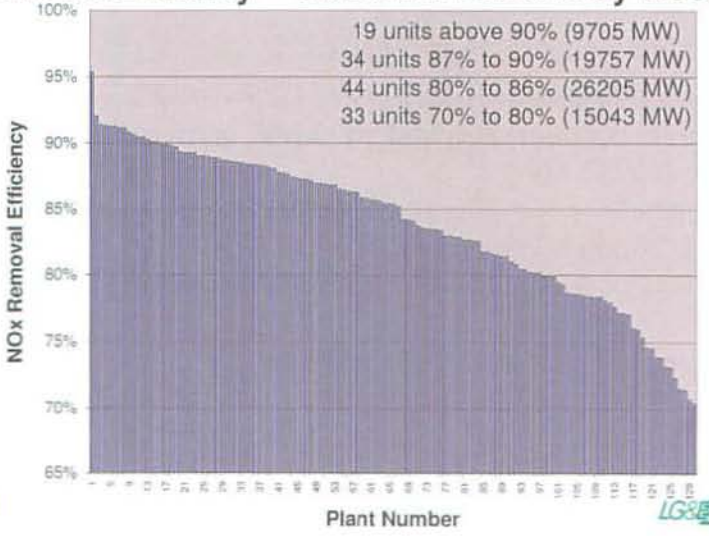
SCR Availability – Method of Calculation

- All emissions data used when unit operating, no data excluded
- Period emission rate determined by sum of emissions (tons NOx) divided by sum of heat input (mmBtu)
- Uncontrolled emission rate (i.e. without SCR) determined from Quarter 1 data
- Removal efficiency determined using Ozone season emission rate compared to uncontrolled

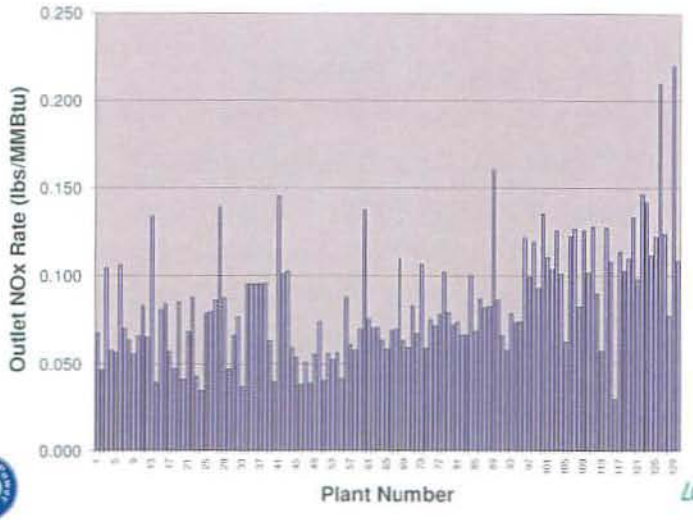
SCR Availability - Results

- 130 SCR units totaling 70,710 MW
- Removal efficiencies from 70% to >90%
- Outlet NO_x rate from 0.03 to 0.22 lbs/mmBtu
- Units ranging in size from 90 to 1300 MW
- Ammonia systems - anhydrous, aqueous, and urea
- Catalyst types - honeycomb, plate, and corrugated
- 12 Month units removed by analysis method

SCR Availability – Removal Efficiency Results



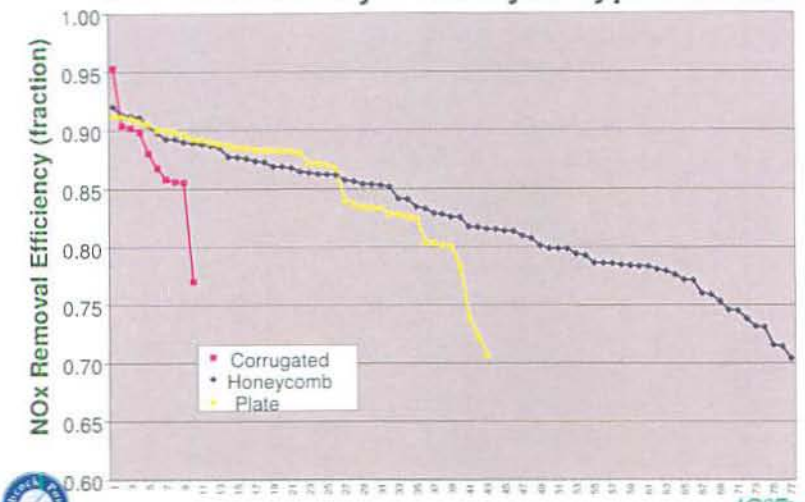
SCR Availability – Outlet NOx Results



SCR Availability – Unit Size

- 19 units between 90 and 1300 MW achieving above 90%
- 34 units between 200 and 1300 MW achieving 87% to 90% (19757 MW)
- 44 units between 200 and 1300 MW achieving 80% to 86% (26205 MW)
- 33 units between 150 and 1300 MW achieving 70% to 80% (15043 MW)
- Availability not sensitive to unit size

SCR Availability – Catalyst Type Results



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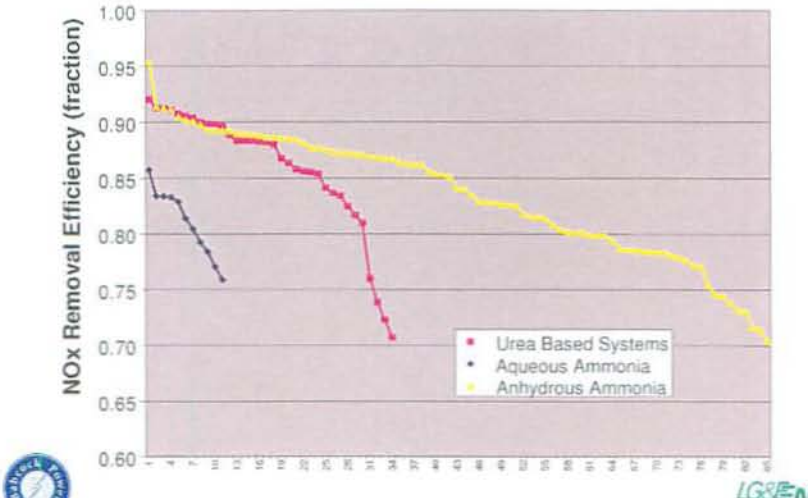
SCR Availability – Ammonia Type Results



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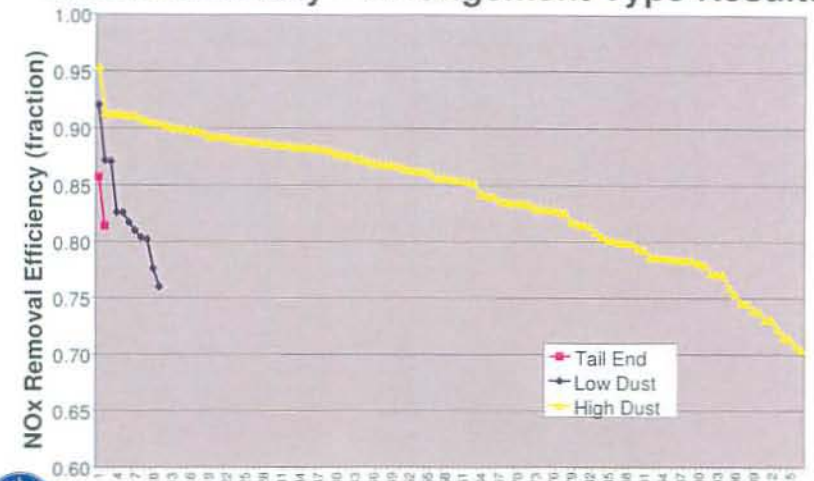
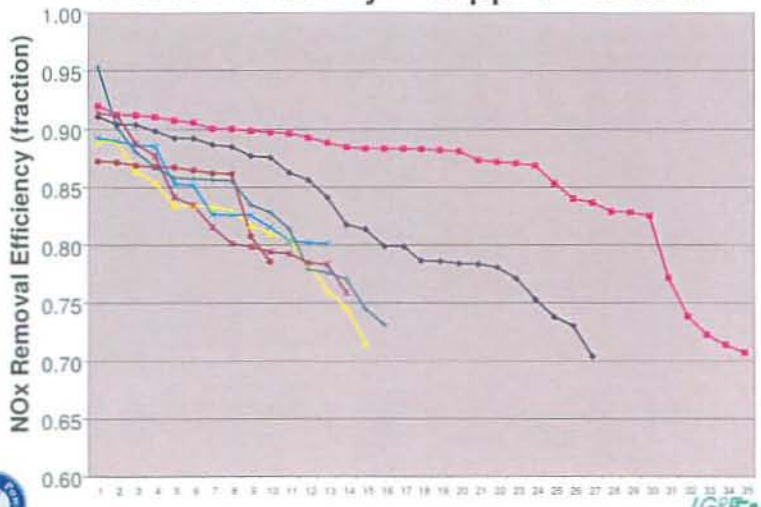
SCR Availability – Arrangement Type Results



SCR Availability – Supplier Results



SCR Availability – Single Unit Review

- Unit background
  - Operating since May 2002
  - Greater than 1000 MW
  - High dust arrangement
  - Urea based ammonia
- Analysis period year 2002 thru 2005

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SCR Availability – Single Unit Review

Year	1 hour average		3 hour rolling average		24 hour rolling average	
	Average (ppm)	Std Dev (ppm)	Average (ppm)	Std Dev (ppm)	Average (ppm)	Std Dev (ppm)
2002	35.70	25.90	35.70	24.90	35.51	19.50
2003	35.25	8.0	35.25	6.92	35.20	4.78
2004	31.75	5.04	31.75	4.06	31.74	2.64
2005 2 months	26.00	4.50	26.00	4.23	26.00	3.60

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